

## Bucking Horse Energy Inc.

Management's Discussion and Analysis  
December 31, 2010

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The following management's discussion and analysis ("**MD&A**") for Bucking Horse Energy Inc. was prepared by management based on information available as at March 30, 2011. It should be reviewed together with the audited consolidated financial statements for the year ended December 31, 2010 and the MD&A and audited consolidated financial statements for the year ended December 31, 2009. Our Annual Information Form, quarterly unaudited interim consolidated financial statements and year-end audited annual consolidated financial statements are filed on SEDAR and are available for review at [www.sedar.com](http://www.sedar.com).

As used in this MD&A, the terms "we", "us", "our", "Bucking Horse" and the "Company" mean Bucking Horse Energy Inc. and our subsidiaries, NRG Holdings Corp. (doing business as GRN Holdings Corp. in the province of British Columbia, Canada) ("**NRG Holdings**"), N Holdings Inc. ("**N Holdings**"), Gemini Energy Corp. ("**Gemini**") and Arrowhead Resources (U.S.A.) Ltd. ("**Arrowhead**").

Unless otherwise noted, all dollar amounts are expressed in US dollars ("**US\$**" or "**\$**") and any references to Common Shares are to common shares in the capital of Bucking Horse Energy Inc., unless the context clearly states otherwise.

Natural gas equivalent ("**Mcf**") amounts have been calculated using a conversion rate of six thousand cubic feet ("**Mcf**") of natural gas per barrel ("**bbl**") of oil or natural gas liquids. A conversion ratio of six Mcf to one bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent equivalency at the wellhead. **Mcf disclosure may be misleading, particularly if used in isolation.**

One million cubic feet equivalent is abbreviated "**MMcfe**". One million British thermal units, a unit of energy, is abbreviated "**MMBTU**".

### Forward-Looking Statements

Certain statements in this MD&A and the documents incorporated by reference contain forward-looking information, which includes forward-looking statements within the meaning of applicable Canadian securities laws. Forward-looking statements are statements which relate to future events or our future performance, including our future financial performance. In some cases, you can identify forward-looking statements by terminology such as "may", "should", "expects", "plans", "anticipates", "believes", "estimates", "predicts", or "potential" or the negative of these terms or other comparable terminology. These statements are only predictions and involve known and unknown risks, uncertainties and other factors, including the risks described in the section titled "Risk Factors" commencing on page 19 and "Risks Relating to the Industry" commencing on page 24 of this MD&A, that may cause the Company's or the industry's actual results, levels of activity, performance or achievements to be materially different from any future results, levels of activity, performance or achievements expressed or implied by these forward-looking statements. No assurance can be given that any of the events anticipated by the forward-looking information and statements will occur or, if they do occur, what benefits we will obtain from them. This MD&A contains forward-looking information and statements, which may include but are not limited to: statements with respect to the financial and operating performance of the company and its subsidiaries; investments objectives and strategies; the business goals and strategies; forecast operating and financial results; planned capital expenditures; the estimated quantity of the drilling plans; the goal to sustain or grow production and reserves through prudent management and acquisitions; potential future market for our products; our plans for, and results of, exploration and development activities; our treatment under governmental regulatory and royalty regimes and tax laws; competitive advantages; business prospects and opportunities; costs and timing of developmental new projects; our management's assessment of future plans and operations; the approval of 5-acre spaced well development on all of our lands; the drilling of infill wells on our Pinedale interest lands has potential to add significantly to our proved reserves inventory; we are positioned to benefit from potentially higher realized prices in the mid-continent and eastern regions of the

United States; the development of the 10 Mesa infill wells should increase our production to approximately 11.5 MMcfe per day by mid-year 2011; plans and timing related to the adoption of International Financial Reporting Standards ("IFRS") and the effects thereof; elections anticipated to be made under IFRS; our anticipated liquidity and various matters that may impact such liquidity; and requirements for additional capital.

While these forward-looking statements, and any assumptions upon which they are based, are made in good faith and reflect our current judgement regarding the direction of our business, actual results will almost always vary, sometimes materially, from any estimates, predictions, projections, assumptions or other future, performance suggested in this MD&A. These assumptions, which include management's current expectations, estimates and assumptions about certain projects and the markets we operate in, the global economic environment, interest rates, estimates of quantities of oil and natural gas from our properties and other sources not currently classified as proved; the successful and timely implementation of capital projects; our ability to generate sufficient cash flow from operations to meet our current and future obligations and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities; the policies of IFRS not changing before we implement them; the impact of IFRS on our financial statements; our ability to satisfy covenants under our credit facilities; the timely receipt of any required regulatory approvals; the impact of increasing competition; our ability to obtain qualified staff, equipment and services in a timely and cost efficient manner; the ability of the operator of the projects in which we have an interest to operate the field in a safe, efficient and effective manor; the timing and costs of pipeline, storage and facility construction and expansion and our ability to secure adequate product transportation; our continued ability to use the Rocky Mountain Express Pipeline; future natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which we operate may prove to be incorrect. A number of risks and uncertainties could cause our actual results to differ materially from those expressed or implied by the forward-looking information and statements, including, but not limited to: the failure of the company to execute our business plans; general economic conditions as they affect us; risks arising from our operations generally; competition; volatility of and assumptions regarding oil and gas prices; the effectiveness of our risk management program; accuracy of cost estimates; fluctuations in commodities prices; fluctuations in product supply and demand; risks inherent in our marketing operations; maintaining a desirable debt to cash flow ratio; our ability to access external source of debt and equity capital; accuracy of our reserves, resources and future production estimates; our ability to replace and expand oil and gas reserves; the reliability of our assets; risks associated with technology and its application to our business; changes in the applicable regulatory framework, including changes in regulatory approval process and land-use designations, royalty, tax, environmental, greenhouse gas, carbon and other laws or regulations, or changes to the associated with compliance; the loss of key management employees; our ability to control our operating costs, general administrative and other expenses; other factors beyond our control; insufficient investor interest in our securities which may impact on our ability to raise additional financing as required; and those factors described in the section titled "Risk Factors" in this MD&A.

These forward-looking statements are based on the estimates and opinions of our management at the time they are made. Although we believe that the expectations reflected in these forward-looking statements are reasonable, we cannot guarantee future results, levels of activity, performance or achievements. Readers of this MD&A are cautioned not to rely on these forward-looking statements. Except as required by applicable securities law, we do not intend to update any of the forward-looking statements in this MD&A to conform these statements to actual results.

## **Overall Performance and Description of Business**

We are engaged in the business of developing, producing and exploring for natural gas and natural gas liquids. We generate almost all of our consolidated revenues from the production and sales of natural gas and natural gas liquids from our Pinedale properties in southwest Wyoming. The Pinedale properties were acquired by way of a plan of arrangement dated March 4, 2008 and are owned by our wholly owned subsidiary, Arrowhead. At December 31, 2010, we also had minor undeveloped properties located in central Washington and a producing property in eastern Alberta, both of which were disposed of subsequent to the year end. Our properties are described as follows:

### **Pinedale Properties, Wyoming, USA**

The Pinedale properties comprise two natural gas producing leasehold properties totalling 11,992 gross acres (3,360 net acres) situated in the Warbonnet and Mesa areas of Sublette County, southwest Wyoming. The Warbonnet property comprises 2,480 gross acres (1,032 net acres), the Mesa property comprises 9,512 gross acres (2,328 net acres). We do not operate our properties; the properties are operated by our operating partners.

The Warbonnet and Mesa properties host commercial reserves of natural gas and natural gas liquids that are produced from the Pinedale natural gas field. The Warbonnet and Mesa properties are located on or proximal to the Pinedale Anticline geological structure situated from six to thirty miles southwest of the town of Pinedale. As of December 31, 2010, our interests includes 38 producing wells (12.6 net) that have been developed primarily on a combination of 80-acre and 40-acre spacing in the Warbonnet area (average working interest of 42%) and 40-acre and 20-acre spacing in the Mesa area (average working interest of 24%). The Warbonnet property is currently approved for 10-acre spacing and plan of well development. State approval for development of 32 wells per quarter section, or one well per approximate 5-acre, was authorized February 8, 2011 for lands that include our Mesa acreage under development. Management anticipates that 5-acre spaced well development on our Warbonnet property will ultimately be approved as area operators are currently developing 5-acre spaced wells within pilot test and approved 5-acre infill areas proximal to our acreage. The drilling of infill wells on our Pinedale interest lands has potential to add significantly to our proved reserves inventory.

We have been shipping our gas on the Rocky Mountain Express Pipeline ("**REX Pipeline**") since January 2008, when the REX Pipeline began shipping on the REX West Pipeline segment. We have a 10 year firm transportation agreement to ship 10,000 MMBTU of gas per day through the REX Pipeline. Effective July 1, 2009, gas transportation service was extended on the REX East Pipeline segment to Lebanon, Ohio. The final segment of the REX Pipeline, from Lebanon, Ohio to Clarington, Ohio commenced full transport service effective November 12, 2009. Natural gas in the Clarington region is currently marketed on par or at a premium to Henry Hub prices. Henry Hub is the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange. Given that our long-term shipping contract on the REX Pipeline, we believe we are positioned to benefit from potentially higher realized prices in the mid-continent and eastern regions of the United States.

### **Wainwright Property, Alberta, Canada**

At December 31, 2010, we owned a 68.75% working interest in oil and gas mineral rights, and one producing gas well, associated with 640 gross developed acres (440 net developed acres) located in the Wainwright area of east central Alberta, Canada. On January 31, 2011, we sold our interest in the Wainwright property, effective January 1, 2011, for gross proceeds of \$15,000. The Wainwright property was written down by \$447,949, to reflect the value of its subsequent sale. As the Wainwright property was not material to our operations, its disposition did not affect our operations.

## **Columbia River Basin Properties, Washington, USA**

In October 2006, we, through our wholly-owned subsidiary N Holdings, acquired certain leases located in Columbia River Basin ("CRB") of Washington State at a public land sale auction. No wells have been drilled upon the leases and there are no reserves or resources attributable to the properties nor has there been any attempt to estimate any reserves or resources in relation to the properties. In 2009, due to disappointing drilling results announced by other companies active in the CRB, we wrote down our Columbia River Basin properties to \$99,000 from \$1,687,951. In 2010 the balance was further written down to \$1. Effective February 1, 2011, we elected to allow our undeveloped leases owned in the Columbia River Basin, Washington State to lapse by not paying annual rentals. As a result, we no longer own any Washington State oil and gas property interests. As the CRB property was not a producing property, this disposition did not have any effect on our continuing operations.

## **Industry and Economic Factors**

Ongoing global economic instability has had a significant negative impact on virtually every segment of the world economy due to many factors including the effects of the subprime lending and general credit market crises, the European debt crisis, volatile energy costs, slower economic activity, decreased consumer confidence, reduced corporate profits and capital spending, adverse business conditions, increased unemployment and liquidity concerns. Although prices for natural gas respond to seasonal pressures, the general economic conditions, both domestically and abroad, and the proliferation of unconventional shale gas development, have had and may continue to have a negative effect on the price for North American natural gas. When prices are relatively low as they have been during the period covered by this MD&A, it is less profitable to drill and financing for drilling operations is more difficult to obtain. Our business, financial condition and results of operations will likely continue to be materially and adversely affected by this trend for the duration of 2011. We have existing commodity hedges that mitigate, but do not eliminate, our risk to price exposure. We cannot predict the timing or duration of an economic slowdown or the strength of an economic recovery, worldwide or in our industry, and cannot predict the extent to which the current economic situation will impact our business. However, the uncertainty regarding the financial markets and worldwide political and economic climates are expected to affect the demand for natural gas in the near future. This change in demand, unmitigated, would likely have a negative impact on our business, financial condition and results of operations.

## **Management Outlook**

A Supplemental Environmental Impact Statement Record of Decision issued by the Bureau of Land Management on September 12, 2008 allows for year round development drilling on lands previously subjected to seasonal drilling stipulations, including our Warbonnet and Mesa properties. Our management anticipates working with our operators to plan the pace of development drilling in both the Mesa and the Warbonnet areas.

In November 2010, a 10 well development program commenced at our Mesa acreage in the Pinedale field property and as at December 31, 2010 we had committed to approximately \$11.3 million in total capital expenditures to fund the initial 10 wells. Individual well costs are forecast at \$4.9 million gross. An additional 11 well program at Mesa is being contemplated during the second half of 2011 utilizing a second rig. This program would commit us to invest an additional \$12.4 million in capital expenditures. The additional rig would be positioned at a recently constructed second simultaneous operations development pad located northwest of current drilling operations. Subsequent to December 31, 2010 during the first quarter of 2011, three wells (0.69 net wells) of the Mesa drilling program have been successfully developed and placed on sales. Our current total net production is approximately 8.5 MMcfe per day. We anticipate that development of the 10 Mesa infill wells should increase our net production to approximately 11.5 MMcfe per day by mid-year 2011. At our Mesa property, we currently have

22 developed producing wells (4.9 net) with an additional inventory of undeveloped proved, probable and possible Mesa locations. At the Warbonnet property, our other significant Pinedale field producing property, we currently have 19 developed and producing wells (8.1 net) and an additional inventory of undeveloped proved, probable, and possible Warbonnet locations.

Our objective is to focus on the development of our Pinedale properties and increase our cash flow and producing reserves base.

## Selected Annual Financial Information

The following table sets forth a summary of our financial results for the years ended December 31, 2010 and December 31, 2009, the four month period ended December 31, 2008, and the year ended August 31, 2008:

<b>(US \$)</b>	<b>Year Ended December 31, 2010</b>	<b>Year Ended December 31, 2009</b>	<b>Four months Ended December 31, 2008</b>	<b>Year Ended August 31, 2008</b>
Total Revenue	13,852,004	12,609,517	4,085,774	15,693,354
Net Income (Loss)	(4,737,320)	(11,329,670)	1,599,474	154,825
Basic Income (Loss) per Share	(0.21)	(0.49)	0.07	0.01
Diluted Income (Loss) per Share	(0.21)	(0.49)	0.07	0.01
Total Assets	176,981,452	173,578,128	170,671,482	177,252,337
Total Non-current Liabilities	103,420,006	97,649,481	88,632,027	92,096,122

Our revenue performance and the income that we realize will vary from period-to-period in relation to the number of wells that we have in production, our production volumes and the prices that we receive for our commodities from time to time. The number of successfully developed wells turned to sales, if any, varies from quarter-to-quarter. Historically, peak commodity pricing for natural gas produced occurs in the fourth and first quarter periods. Our operations, if profitable, are also subject to taxes in the jurisdictions in which we conduct our business. The net income variance year to year is due to a number of factors, including changes in hedging valuations and operating income.

The discussion and analysis of our financial condition and results of operations is based on our consolidated financial statements, which have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). Application of GAAP requires the use of estimates, judgements and assumptions that affect the reported amounts of assets and liabilities as of the date of the financial statements as well as the revenues and expenses reported during the period. Changes in these estimates, judgements and assumptions will occur as a result of future events, and accordingly, actual results could differ from amounts estimated.

## Results of Operations

### Year ended December 31, 2010 compared to the year ended December 31, 2009:

Net US production from Arrowhead's interests during the year ended December 31, 2010 totalled approximately 2,609 MMcf of natural gas and 22.9 thousand barrels of natural gas liquids, or 2,746 MMcfe averaging 7.5 MMcfe/day compared to 3,240 MMcf of natural gas and 27.9 thousand barrels of natural gas liquids, or 3,407 MMcfe averaging 9.3 MMcfe/day for the

year ended December 31, 2009. The decrease in production rates over the compared period is primarily due to natural production rate declines associated with the field and that no new producing wells were developed in 2010 while during the year ended December 2009 flush production was realized from two wells that were developed. Prices we realized in the US for the year ended December 31, 2010 averaged \$4.66 per Mcf of natural gas and \$69.09 per barrel of natural gas liquids compared to \$3.42 per Mcf of natural gas and \$49.06 per barrel of natural gas liquids for the year ended December 31, 2009.

Canadian production during the year ended December 31, 2010 totalled approximately 34 MMcf of natural gas averaging 94 Mcf/day compared to 48 MMcf averaging 132 Mcf/day for the year ended December 31, 2009. The decrease in production rates over the compared periods is due to the normal production rate decline attributed to the Wainwright well. Natural gas prices realized from the our Canadian property for the year ended December 31, 2010 averaged C\$3.43 per Mcf compared to C\$3.79 per Mcf for the year ended December 31, 2009.

We have existing commodity hedges that mitigate, but not eliminate, our risk exposure to price volatility. During the year period ended December 31, 2010, the realized gain on commodity derivative instruments was \$2,862,065. Our derivative contracts are tabled on page 9.

The net loss for the year ended December 31, 2010 decreased to \$4,737,320 compared to a net loss of \$11,329,670 for the year ended December 31, 2009. The change is due to a number of factors, including changes in hedging valuations and operating income. Hedging activity produced a realized gain of \$2,862,065 and an unrealized gain of \$3,906,352 (overall gain of \$6,768,417) in the year ended December 31, 2010 versus a realized gain of \$6,969,194 and an unrealized loss of \$2,202,893 (overall gain of \$4,766,301) in the year ended December 31, 2009. Operating income increased for the year ended December 31, 2010 to \$1,395,593 compared to a loss of \$314,077 for the year ended December 31, 2009. The operating income variance is primarily due to increased production revenues resulting from higher realized natural gas prices in 2010 and reduced non-cash depletion.

Production revenues for the year ended December 31, 2010 totalled \$13,852,004 compared to \$12,609,517 for the year ended December 31, 2009. Of these revenues, \$13,737,489 were derived from the our Pinedale properties and \$114,515 were derived from our Wainwright properties. The production revenue variance is due to higher commodity prices realized by us from production volumes sold during the periods compared.

Production expenses for the year ended December 31, 2010 totalled \$12,456,411 consisting of \$5,657,687 in non-cash accretion and depletion costs, \$5,541,952 in direct operating expenses, \$1,253,995 in state resource taxes and \$2,777 in Canadian production royalties compared to production expenses for the year ended December 31, 2009 of \$12,923,594, consisting of \$6,438,722 in non-cash accretion and depletion costs, \$5,378,584 in direct operating expenses, \$1,096,087 in state resource taxes and \$10,201 in Canadian production royalties. The variance in production expenses is largely due to a decrease in the non-cash depletion expense.

Other expenses and income, including non-cash items, for the year ended December 31, 2010 totalling \$4,606,236, consisted primarily of general and administration expenses of \$831,097, professional fees of \$892,209, a realized gain on commodity derivative instruments of \$2,862,065, an unrealized gain on derivative instruments of \$3,906,352, non-cash accretion expense on our debentures of \$1,554,571, interest expense of \$7,610,464, and a foreign exchange gain of \$466,378. This is compared to other expenses, including non-cash items, for the year ended December 31, 2009 totalling \$10,280,792, consisting primarily of general and administration expenses of \$682,907, professional fees of \$928,598, a realized gain on commodity derivative instruments of \$6,969,194, a unrealized loss on derivative instruments of \$2,202,893, non-cash accretion expense on our debentures of \$1,142,419, interest expense of

\$6,926,668, a writedown of the promissory note and accrued interest of \$3,909,729, a writedown on our Columbia River Basin property in Washington, USA of \$1,588,951 and a foreign exchange gain of \$353,592.

Contingent Liability: In 2006, our wholly-owned subsidiary, Arrowhead, and seven other unrelated defendants were served with a lawsuit alleging that certain properties, including some of the properties owned by Arrowhead, are subject to a 5% net profits interest owned by the plaintiffs and that all of the defendants, including Arrowhead, are in default of their obligations under this 5% net profits interest to pay money to the plaintiffs. Arrowhead leases that are encumbered by this lawsuit consist of five Warbonnet leases totalling 2,040 gross acres (867 net acres) and at the time, 13 developed wells (5.5 net). On March 23, 2010, the Wyoming Supreme Court upheld a lower courts' judgement against the defendants and following remand to the District Court, an amended judgement was entered into for \$4,812,111. Our share of this judgement totalled \$58,234. Management is of the opinion that our share of the expenses for the years 2009 through to present are financially immaterial.

Normal Course Issuer Bid: In August 2010, the Toronto Stock Exchange (the "TSX") accepted our Notice of Intention to Make a Normal Course Issuer Bid (the "2010 Notice") pursuant to which we indicated that we intend to make a normal course issuer bid (the "2010 NCIB") for certain of our outstanding Common Shares on the terms set forth in the 2010 Notice. At the time of filing the 2010 Notice, our Board of Directors was of the belief, and continues to be of the belief, that the purchase of Common Shares from time-to-time at appropriate prices is an advantageous use of our funds. As of August 4, 2010, we had 22,726,213 Common Shares outstanding. Under the rules of the TSX, in the period commencing on August 10, 2010 and ending on August 9, 2011, we may acquire up to 750,000 Common Shares, which represents 3.3% of the Common Shares outstanding as at August 4, 2010. The average daily trading volume for the prior six months to the acceptance of the 2010 Notice was 869 Common Shares. Pursuant to the 2010 NCIB, we may acquire a daily limit of 1,000 Common Shares. Any Common Shares purchased pursuant to the 2010 Notice will be returned to treasury and cancelled. The Common Shares will be purchased at market price of the shares at the time of purchase and will be purchased on behalf of us by a registered investment dealer through the facilities of the TSX. The funding for any purchase of Common Shares pursuant to the 2010 NCIB will be financed out of our working capital.

As of December 31, 2010, 37,600 Common Shares were purchased pursuant to the 2010 NCIB at an average purchase price of C\$3.28 of which 35,800 have been returned to treasury and cancelled.

Under a prior Normal Course Issuer Bid Notice (the "2009 Notice") accepted by the TSX on July 9, 2009, (the "2009 NCIB") we were authorized to acquire up to 750,000 Common Shares, representing 3.26% of our Common Shares outstanding as at July 6, 2009, during the period commencing on July 13, 2009 and ending on July 12, 2010. The average daily trading volume for the prior six months to the acceptance of the 2009 Notice was 251 Common Shares. Pursuant to the 2009 NCIB, we were authorized to acquire a daily limit of 1,000 Common Shares. Any shares purchased pursuant to the 2009 Notice were returned to treasury and cancelled. Common Shares were purchased at the market price of the shares at the time of purchase and were purchased on behalf of us by a registered investment dealer through the facilities of the TSX. The funding for the purchase of Common Shares pursuant to the 2009 NCIB was financed out of our working capital. At July 12, 2010 being the last day of the 2009 NCIB, we had purchased a total of 268,300 Common Shares at an average purchase price of C\$2.97 per share on the open market pursuant to the 2009 NCIB. All Common Shares purchased through the 2009 NCIB were returned to treasury and cancelled.

Debt Settlement: On November 19, 2009, we reached a settlement with Q Investments Ltd. ("Q Investments") respecting a debt owed to us by Q Investments since March 4, 2008. The

debt was incurred as a result of our sale to Q Investments of 12,000,000 common shares of Exxel Energy Corp. ("Exxel") conducted as part of our Plan of Arrangement, which closed on March 4, 2008. On May 30, 2008, Exxel consolidated its shares and changed its name to XXL Energy Corp. ("XXL"). As a result, the 12,000,000 (pre-consolidated) common shares of Exxel converted to 600,000 (post-consolidated) common shares of XXL. Both Q Investments and XXL are non-arm's length to us.

The debt remaining due from Q Investments was C\$4,045,200 as at June 30, 2009 but was written down to C\$1,365,261 on our quarterly financials of that date, in accordance with a business valuation performed by an independent chartered business valuator, who was engaged by us and Q Investments to prepare a comprehensive valuation report on the debt due. Security granted for the note at issuance was 300,000 XXL shares to be held in escrow until full payment of the debt.

An independent fairness opinion, prepared by the same independent business valuator, concluded that the transfer of the 300,000 XXL shares in settlement of the debt would be fair to us. However, we agreed to accept 600,000 common shares of XXL, being the entire number of XXL shares originally sold to Q Investments, in return for a full settlement of the amount due under the debt. .

According to the debt settlement agreement between us and QIL, the 600,000 shares of XXL were transferred into Gemini's name in March 2010 and the promissory note has been settled.

Financial Advisory Agreement: On July 13, 2010, we entered into a Financial Advisory Agreement with BMO Capital Markets ("**BMOCM**") whereby BMOCM will act as our exclusive financial advisor. The Financial Advisory Agreement is for a minimum period of six months and shall continue thereafter until terminated by either party. Under the Financial Advisory Agreement, BMOCM, receives a monthly fee of \$20,000 plus any out-of-pocket expenses incurred during the engagement.

### **Financial Derivative Contracts**

We hold various financial derivative contracts to manage price risk. As at December 31, 2010, the unrealized gain on outstanding derivative financial contracts was \$3,906,352. The realized gain on settlement of derivative financial contracts during the period was \$2,862,065. Both amounts have been included in other expenses for the period.

#### (a) Commodity Hedge Contracts

On February 18, 2009, we entered into a swap contract, committing 2,500 MMBTU/day in the calendar year 2010 at the price of \$6.20. On June 11, 2009, we entered into two new commodity swap contracts, committing an additional 1,000 MMBTU/day in calendar 2010 and 3,000 MMBTU/day in calendar 2011 at prices of \$6.48 and \$7.23 per MMBTU respectively. On October 19, 2009, three additional commodity swap contracts were entered into, committing an additional 1,000 MMBTU/day each in calendar 2010 and 2011 and 3,500 MMBTU/day in calendar 2012 at prices of \$6.50, \$7.11 and \$7.22 per MMBTU respectively.

We began the 2010 fiscal year with derivative financial contracts to manage price risk on a portion of our natural gas production for the periods referenced below:

Type	Volume MMBTU/Day	Contract Period	Price \$/MMBTU
Swap <sup>(1)</sup>	2,500	Calendar 2010	\$6.20/MMBTU
Swap <sup>(1)</sup>	1,000	Calendar 2010	\$6.48/MMBTU
Swap <sup>(1)</sup>	1,000	Calendar 2010	\$6.50/MMBTU
Swap <sup>(1)</sup>	3,000	Calendar 2011	\$7.23/MMBTU
Swap <sup>(1)</sup>	1,000	Calendar 2011	\$7.11/MMBTU
Swap <sup>(1)</sup>	3,500	Calendar 2012	\$7.22/MMBTU

<sup>(1)</sup> Appalachia basis

On March 21, 2011, we entered into three derivative financial swap contracts for the periods and volumes referenced below:

Type	Volume MMBTU/Day	Contract Period	Price \$/MMBTU
Swap <sup>(1)</sup>	500	Apr - Dec 2011	\$4.52/MMBTU
Swap <sup>(1)</sup>	1,000	Jan - Dec 2012	\$5.02/MMBTU
Swap <sup>(1)</sup>	4,000	Jan - Mar 2013	\$5.44/MMBTU

<sup>(1)</sup> Appalachia basis

(b) Foreign Exchange Contracts

On March 5, 2009, we contracted to purchase C\$4,584,600 during calendar 2010 at an exchange rate of C\$1.2735 per US\$.

On May 28, 2009, we monetized this contract and realized a gain of \$760,731.

In May 2010, we contracted to purchase a total of C\$2,138,564.76 with terms referenced as follows:

US\$ Sold	Contract Period	Exchange Rate
\$83,333.33/month	June 2010 to May 2011	1.0642
\$83,333.00/month	June 2010 to May 2011	1.0744

Derivative financial instruments are measured at fair value with gains and losses recorded in net earnings.

## Summary of Quarterly Results

The following table presents selected unaudited quarterly consolidated financial information for the last eight quarters:

(US\$)	2010				2009			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Total Revenue	\$3,084,300	\$3,363,345	\$3,356,863	\$4,047,496	\$3,339,296	\$3,135,417	\$2,805,908	\$3,328,896
Net Income (Loss)	(\$2,530,689)	(\$1,959,572)	(\$3,151,094)	\$2,904,035	(\$2,040,554)	(\$4,435,579)	(\$4,458,584)	(\$394,953)
Basic Income (Loss) per Share	(0.21)	(0.09)	(0.14)	0.13	(0.09)	(0.19)	(0.19)	(0.02)
Diluted Income (Loss) per Share	(0.21)	(0.09)	(0.14)	0.13	(0.09)	(0.19)	(0.19)	(0.02)

## Liquidity

Our cash and cash equivalents at December 31, 2010 totalled \$4,425,957 compared to \$6,751,735 at December 31, 2009.

As of December 31, 2010, our working capital increased to \$9,418,277 from \$8,989,683 at December 31, 2009.

Our objective is to meet our operating and capital requirements by a combination of cash flow from current and future well production, re-investment of current capital and utilization of our long term credit facility of \$38,000,000, of which, as of March 31, 2011, we have used \$24,500,000. However, production volumes and the market price that we receive for natural gas and natural gas liquids that we produce and sell determine our revenue from operations. As a consequence, our ability to obtain additional capital is substantially dependent on the price of natural gas. Future cash flows and the continued availability of financing are subject to a number of uncertainties including, by way of example, production rates, the price of natural gas, the results of our drilling programs.

The following are our contractual maturities and financial liability as of December 31, 2010:

Contractual Obligations (US\$)	Payments Due by Period				
	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Long term debt <sup>(1)</sup>	49,266,036			10,054,293	39,211,743
Accounts payable and accrued liabilities	3,124,095	3,124,095			
State resource taxes payable	624,614	337,853	286,761		
Income taxes payable	77,460	77,460			
Other long-term obligations <sup>(2)</sup>	137,562				137,562
Line of credit <sup>(3)</sup>	18,500,000		18,500,000		
Development program	9,300,000	9,300,000			
Total contractual obligations	81,029,767	12,839,408	18,786,761	10,054,293	39,349,305

- (1) Our long term debt consists of six convertible debentures, as discussed in more detail below in the amount of C\$49,000,000 converted using the Bank of Canada close rate on December 31, 2010.
- (2) Our other long-term obligations consists of our asset retirement obligation.
- (3) On January 18, 2011, we drew an additional \$6,000,000 from our line of credit.

## Capital Resources

In connection with a plan of arrangement among our Company, Gemini, Arrowhead, and a senior bank, as administrative agent, and each of the lenders from time-to-time party thereto (collectively, the "**Lenders**"), the parties entered into a credit agreement (the "**Credit Agreement**") dated March 4, 2008, whereby the Lenders agreed to make a five year senior revolving credit facility in the aggregate principal amount of up to \$100,000,000, with an initial borrowing base of \$30,000,000 (the "**Facility**"), available to Arrowhead pursuant to the terms set out in the Credit Agreement. Our Company and Gemini guaranteed the Facility. The Facility is available to provide working capital to Arrowhead and to enable Arrowhead to make distributions to Gemini which may then be further distributed to us for general corporate purposes. The Facility is secured by mortgages on the oil and gas properties of Arrowhead.

The Facility has an interest rate that floats, based on both the LIBOR rate and a spread, which will increase based on the percentage of availability drawn, resulting in an interest rate of approximately 2.55% at December 31, 2010 (December 31, 2009 – 1.99%).

On August 23, 2010 the Credit Agreement was amended, increasing the borrowing base to \$38,000,000. At December 31, 2010, we had drawn \$18,500,000 from the Facility and had \$19,500,000 of available credit. On January 18, 2011, we drew an additional \$6,000,000 from the Facility. At March 30, 2011, we had drawn \$24,500,000 from the Facility and had \$13,500,000 of available credit.

We are required by certain Credit Agreement covenants to ensure that Arrowhead's interest coverage ratio is greater than 2.5 to 1.0, that Arrowhead's ratio of total indebtedness to earnings before interest income taxes, depletion, depreciation and accretion, and exploration expenses is greater than 3.5 to 1.0, and that our current ratio is greater than 1.0 to 1.0. We were in compliance with all of these covenants at December 31, 2010.

Our long term debt as at December 31, 2010 is comprised of six secured convertible debentures as described below:

On March 4, 2008, we issued two convertible debentures (the "**First Debentures**"), one to John Hislop and Bradley Windt (collectively, the "**Debenture Lenders**"). Each of the First Debentures is in the principal amount of \$ 9,551,579 (C\$9,500,000), has a term of ten years, earned interest initially at a rate of 10% during the first six years and 15% during the last four years. The Debenture Lenders may elect to accelerate the maturity date to the sixth anniversary date at any time during the first five years. Effective May 16, 2008, as a result of an interest rate acceleration provision, the interest rate applicable to the First Debentures at that time increased from 10% to 15%. Each of the First Debentures is convertible into units during the first five years at a conversion price of C\$4.875 per unit. Each unit consists of one Common Share and one share purchase warrant, which entitles the holder to purchase one additional Common Share for C\$4.875 until the fifth anniversary of the date of issuance, at which date these share purchase warrants will expire.

On March 4, 2008, we issued two additional convertible debentures (the "**Second Debentures**") to each of the Debenture Lenders. Each of the Second Debentures is in the principal amount of \$5,027,147 (C\$5,000,000), will mature on August 4, 2014. Interest was initially payable monthly at a rate of 10% per annum for the first six years of the term and at a rate of 15% during the last four years. Effective May 16, 2008, as a result of an interest rate acceleration provision, the interest rate applicable to the Second Debentures at that time increased from 10% to 15%. All or any portion of the amount outstanding under these Second

Debentures from time-to-time is convertible into units at the option of the holder at a price of C\$4.00 per unit. Upon conversion, each unit consists of one Common Share and one share purchase warrant. The purchase warrant has expired with none of the warrants being exercised.

Also on March 4, 2008, we issued two additional convertible debentures (the "**Third Debentures**") to each of the Debenture Lenders. Each of the Third Debentures is in the principal amount of \$10,054,293 (C\$10,000,000), has a term of ten years, initially earned interest at a rate of 10% during the first six years and 15% during the last four years. Effective May 16, 2008, as a result of an interest rate acceleration provision, the interest rate applicable to the Third Debentures at that time increased from 10% to 15%. Each of the Third Debentures is convertible into units during the first five years at a conversion price of C\$4.875 per unit. Each unit consists of one Common Share and one share purchase warrant, which entitles the holder to purchase one additional Common Share for C\$4.875 until the fifth anniversary of the closing date, at which date the share purchase warrants will expire.

The rate acceleration provision included in the First Debentures, Second Debentures, and Third Debentures (collectively, the "**Debentures**") requires that in the event the indebtedness resulting from the Credit Agreement described below exceeds the aggregate amount of \$12,000,000, the rate of interest payable on the principal amount of the Debentures shall increase to a rate of interest equal to the then applicable rate of interest payable plus 5% per annum for the period of time that the Credit Agreement indebtedness exceeds the sum of \$12,000,000. Effective May 16, 2008, the indebtedness exceeded \$12,000,000 and the new rate of interest for the Debentures of 15% per annum took effect.

Repayment of the Debentures is guaranteed by our subsidiary Arrowhead, which has provided a mortgage and security agreement to each of the Debenture Lenders which is subordinated to other debt under the Facility. The Debentures are redeemable by us upon thirty days written notice without penalty or bonus; however, the Debenture Lenders may elect to convert all or any of the Debentures in lieu of redemption during the thirty-day notice period.

We anticipated that we will have sufficient cash and financing available to pay for our capital commitments and consequently do not anticipate any problems meeting existing capital commitments as they become due.

## **Off-Balance Sheet Arrangements**

We do not have any off-balance sheet financing type arrangements that have or are reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

## **Transactions with Related Parties**

On November 10, 2006, we entered into a loan agreement with Q Investments, whereby Q Investments provided us with a loan in the principal amount of \$1,327,434 (C\$1,500,000). On November 10, 2006, John Hislop was, at that time, a director and a control person of Q Investments and the President, Chief Executive Officer and a director of our Company. As a condition to the closing of the Plan of Arrangement on March 4, 2008, Gemini sold 12,000,000 shares of common stock of Exxel (now known as XXL) to Q Investments, for total consideration of \$15,106,980 (C\$15,040,800). The purchase price was initially paid by Q Investment's issuance of a promissory note for the full amount of the purchase price, having a term of one year and bearing interest at the rate of 15% per annum. The note was reduced to \$9,537,381 (C\$9,495,600) by Q Investments delivering 2,373,900 common shares of Gemini at C\$4.00 per share pursuant to the Plan of Arrangement. The note was further reduced to \$4,045,200 by Q Investments surrendering a promissory note that was issued by us in the

principal sum of \$1,506,600 (C\$1,500,000) together with accrued interest. During fiscal 2009, the settlement of the promissory note was negotiated whereby Q Investments exchanged 600,000 shares of XXL to us in return for the retirement of the note and the related accrued interest. Accordingly, the promissory note and accrued interest was written down to the fair value of the 600,000 shares of XXL totalling C\$84,000. The write down of C\$4,464,911 has been included in other expenses in the consolidated statement of operations for the year ended December 31, 2009. In March 2010, the shares were transferred to us and the note was settled.

On March 4, 2008, we issued six debentures to John Hislop and Bradley Windt in connection with our acquisition of Gemini. The debentures are described above in more detail above under the heading "Capital Resources".

In May 2010, Q Investments entered into a share purchase agreement with us to acquire our 1,000,000 common shares of Giant for payment of C\$50,000.

On July 13, 2010, we entered into a revised management services agreement (the "MSA") effective January 1, 2010 with a private management company wholly-owned by John Hislop, a shareholder and one of the Debenture Lenders. Under the MSA, the management company is to assist us by providing management, administration, compliance, accounting, and information services, as well as provide office space and utilities for our Company. The MSA shall continue on a month-to-month basis until terminated by one of the parties. Pursuant to the MSA, a monthly administrative fee of C\$35,000 plus any out of pocket expenses and specialized management expenses incurred shall be paid to the management company. Fees incurred during 2010 amounted to \$420,000.

## **Fourth Quarter**

### **Three-month period ended December 31, 2010 compared to the three-month period ended December 31, 2009:**

Net US production from Arrowhead's interests during the three-month period ended December 31, 2010 totalled approximately 613 MMcf of natural gas and 5.7 thousand barrels of natural gas liquids, or 619 MMcfe averaging 6.7 MMcfe/day compared to 712 MMcf of natural gas and 6.6 thousand barrels of natural gas liquids, or 752 MMcfe averaging 8.2 MMcfe/day for the three months ended December 31, 2009. The decrease in production rates over the compared period is primarily due to natural production rate declines associated with the field and that no new producing wells have been developed through the period ending December 31, 2010. Physical prices realized by us in the US averaged \$4.30 per Mcf of natural gas and \$74.19 per barrel of natural gas liquids for the three-month period ended December 31, 2010 compared to \$4.03 per Mcf of natural gas and \$65.79 per barrel of natural gas liquids for the three months ended December 31, 2009.

Canadian production during the three-month period ended December 31, 2010 totalled approximately 7 MMcf of natural gas averaging 72 Mcf/day compared to 10 MMcf averaging 110 Mcf/day for the three months ended December 31, 2009. The decrease in production rates over the compared periods is due to the production rate decline attributed to the Wainwright well. Natural gas prices realized from our Wainwright properties for the three-month period ended December 31, 2010 averaged C\$3.13 per Mcf compared to C\$4.24 per Mcf for the three months ended December 31, 2009.

The net loss for the three months ended December 31, 2010 increased to a net loss of \$2,530,689 compared to a net loss of \$2,040,554 for the three months ended December 31, 2009. Operating income decreased for the three months ended December 31, 2010 to \$68,093 compared to an operating income of \$315,942 for the three months ended December

31, 2009. The operating income variance is primarily attributable to decreased revenues as detailed below.

Production revenues for the three-month period ended December 31, 2010 totalled \$3,084,300 compared to \$3,339,296 for the three-month period ended December 31, 2009. Of these revenues, \$2,969,782 were derived from our Pinedale properties and \$114,518 were derived from our Wainwright properties. The production revenue variance is due to natural production rate declines associated with the field and the fact that no new producing wells have been developed through the period ending December 31, 2010.

Production expenses for the three-month period ended December 31, 2010 totalled \$3,016,207 consisting of \$1,285,357 in non-cash accretion and depletion costs, \$1,468,849 in direct operating expenses, \$261,828 in state resource taxes and \$173 in Canadian production royalties compared to production expenses for the three-month period ended December 31, 2009 of \$3,023,354, consisting of \$1,366,516 in non-cash accretion and depletion costs, \$1,365,279 in direct operating expenses, \$291,244 in state resource taxes and \$315 in Canadian production royalties.

Other expenses and income, including non-cash items for the three-month period ended December 31, 2010 resulted in other expenses of \$897,137 and consisted of a general and administration expenses of \$304,760, professional fees of \$261,038, a realized gain on commodity derivative instruments of \$988,055, an unrealized gain on derivative instruments of \$1,269,672, non-cash accretion expense on our debentures of \$373,751, interest expense of \$1,959,103 and foreign exchange loss of \$484,972, compared to other expenses including non-cash items for the three-month period ended December 31, 2009 of \$2,331,234, and consisted of general and administration expenses of \$273,387, professional fees of \$343,170, a realized gain on commodity derivative instruments of \$1,718,800, a non-cash gain on derivative instruments of \$1,186,975, non-cash accretion expense on our debentures of \$341,774, interest expense of \$1,832,814 and foreign exchange gain of \$722,975.

During the three-month period ended December 31, 2010, a total of 37,600 Common Shares were repurchased through the 2010 NCIB at an average price of \$3.28. On October 19, 2010, 5,300 of the repurchased Common Shares were returned to treasury and cancelled and an additional 30,500 Common Shares were returned to treasury and cancelled on December 8, 2010.

## **Proposed Transactions and Subsequent Events**

As of the date of this MD&A, a total of 43,700 Common Shares were purchased pursuant to the 2010 NCIB at an average purchase price of C\$3.31 and to date, 42,700 Common Shares have been returned to treasury and cancelled.

On January 31, 2011, we purchased \$4.00 NYMEX put options for the period April 2011 through October 2011 on 5,000 MMBtu/day, for a total of 1,070,000 MMBtu.

Effective February 1, 2011, we elected to allow our undeveloped leases owned in the Columbia River Basin, Washington State to lapse by not paying annual rentals. As a result, we no longer own any Washington State oil and gas property interests.

On January 31, 2011, we sold our entire interest in a minor property located in Wainwright, Alberta area to a third party effective January 1, 2011 for gross proceeds of \$15,000. As a result, we no longer own any Canadian oil and gas property interests.

## **Critical Accounting Estimates**

The preparation of financial statements in conformity with Canadian GAAP requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods.

Our management routinely makes judgements and estimates about the effects of matters that are inherently uncertain. As the number of variables and assumptions affecting the probable future resolution of the uncertainties increase, these judgements become even more subjective and complex. We have identified certain accounting policies that are the most important to the portrayal of our current financial condition and results of operations.

The key elements and assumptions that we have made under these principles and their impact on the amounts reported in the December 31, 2010 audited year-end consolidated financial statements remain substantially unchanged from those described in our December 31, 2009 audited year-end consolidated financial statements.

Please refer to Note 2 of our 2010 audited year-end consolidated financial statements for our Significant Accounting Policies.

## **Significant Accounting Policies**

The significant accounting policies used by us are disclosed in the notes to our annual year-end consolidated financial statements for the year ended December 31, 2010. 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. The following discussion outlines such accounting policies and is included in the MD&A to aid the reader in assessing the significant accounting policies and practices of our company and the likelihood of materially different results being reported. Our management reviews its estimates regularly.

The following significant accounting policies outline the major policies involving critical estimates:

### **Proved Oil and Gas Reserves**

Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will differ from the estimated proved reserves. The estimated quantities of proved crude oil, natural gas liquids and natural gas are derived from geological and engineering data that demonstrate with reasonable certainty the amounts that can be recovered in future years from known reservoirs under existing economic and operating conditions. Reserves are considered proved if they can be produced economically as demonstrated by either actual production or conclusive formation tests. The oil and gas reserve estimates are made using all available geological and reservoir data as well as historical production data. Estimates are reviewed and revised as appropriate. Revisions occur as a result of changes in prices, costs, fiscal regimes, reservoir performance or a change in our plans. The effect of changes in proved oil and gas reserves on our financial position is described under the headings "Depletion Expense" and "Impairment of Long Lived Assets".

### **Depletion Expense**

We use the full cost method of accounting for exploration and development activities. In accordance with this method of accounting, all costs associated with exploration and development are capitalized whether successful or not. The aggregate of net capitalized costs

and estimated future development costs less estimated salvage values is amortized using the units-of-production method based upon proved oil and gas reserves. With all other factors remaining constant, an increase in estimated proved oil and gas reserves would result in a corresponding reduction in depletion expense. With all other factors remaining constant, a decrease in estimated future development costs would result in a corresponding reduction in depletion expense.

### **Impairment of Long Lived Assets**

We are required to review the carrying value of all property, plant and equipment, including the carrying value of oil and gas assets, for potential impairment. The carrying value of our petroleum and natural gas properties must not exceed their fair value. The fair value is equal to the estimated future cash flows from proved and probable reserves using future price forecasts and costs discounted at a risk-free rate.

If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the long lived asset is charged to income.

### **Asset Retirement Obligation**

Asset retirement obligations are initially measured at fair value when they are incurred, which is the discounted future value of the estimated liability. This requires an estimate to be made of the future costs of retiring the asset at the point in time the asset is acquired.

### **Income Tax Accounting**

The determination of our income and other tax liabilities requires interpretation of complex laws and regulations. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

### **Stock-based Compensation**

The fair value of stock options is determined by the Black-Scholes Option Pricing Model with assumptions for risk-free interest rates, dividend yields, volatility factors of the expected market price of the Common Shares and an expected life of the options. The fair value of direct awards of stocks is determined by the quoted market price of our stock.

### **Legal Environmental Remediation and Other Contingent Matters**

We are required to both determine whether a loss is probable based on judgement and interpretation of laws and regulations and determine that the loss can reasonably be estimated. When the loss is determined it is charged to earnings. Our management must continually monitor known and potential contingent matters and make appropriate provisions by charges to earnings when warranted by circumstance.

### **Changes in Accounting Policies Including Initial Adoption**

#### **Recent Accounting Pronouncements**

We have assessed new and revised accounting pronouncements that have been issued that are not yet effective and determined that the following may affect the financial disclosures and results of operations of our company:

(i) Business Combinations

In January 2009, the CICA issued Section 1582, *Business Combinations*, which requires that all assets and liabilities of an acquired business be recorded at fair value at acquisition. Obligations for contingent considerations and contingencies will also be recorded at fair value at the acquisition date. The standard also states that acquisition-related costs will be expensed as incurred and that restructuring charges will be expensed in the periods after the acquisition date. The Section applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period on or after January 1, 2011. We have not yet adopted this standard.

(ii) Consolidations and Non-Controlling Interest

In January 2009, the CICA issued Section 1601, *Consolidations*, and Section 1602, *Non-Controlling Interests*. Section 1601 establishes standards for preparing consolidated financial statements and Section 1602 establishes standards for accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. These standards apply to interim and annual consolidated financial statements relating to fiscal years beginning on or after January 1, 2011. We have not yet adopted these standards.

(iii) Transition to International Financial Reporting Standards (IFRS)

Commencing on January 1, 2011 International Financial Reporting Standards (IFRS) are the generally accepted accounting principles in Canada. The changeover date of January 1, 2011 requires the restatement, for comparative purposes, of amounts reported by us for the year ended December 31, 2010, including the opening balance sheet as at January 1, 2010. The project to convert to IFRS is being managed by members of the finance and accounting group, who have engaged in IFRS educational programs and continue to develop the Company's adoption to IFRS.

Summary of Exemptions Available

In July 2009, the International Accounting Standards Board approved amendments and released 'Additional Exemptions for First-time Adopters' which prescribes transitional exemptions for oil and gas companies following full cost accounting. The amendment allows an entity that used full cost accounting under Canadian GAAP to elect, at its time of adoption, to measure exploration and evaluation assets at the amount determined under the Canadian GAAP and to measure oil and natural gas assets in the development or production phases by allocating the amount determined under Canadian GAAP for those assets to the underlying assets pro rata using reserve volumes or reserve values as of the date of transition, subject to an impairment test as prescribed under IFRS. This exemption will allow us to apply IFRS to our full cost pools on a prospective basis, from date of transition to IFRS. We expect to utilize this exemption and elect on date of transition to report items of property plant and equipment at cost. IFRS 1 also provides a number of other optional exemptions and mandatory exceptions in certain areas to the general requirement for full retrospective application which include the following:

Business Combinations – IFRS 1 would allow us to use the IFRS rules for business combinations on a prospective basis. We plan to use this exemption.

The transition from Canadian GAAP to IFRS is significant and may materially affect our reported financial position and results of operations. Key differences identified by the Company that will impact the financial statements and the current status of those items are noted as follows:

Debentures - Under Canadian GAAP Debentures are required to be accounted for as a compound instrument with both a debt and equity component. A policy choice available

under Canadian GAAP to value the equity component with the balance of the debenture value being assigned to debt is no longer available. The treatment under IFRS also requires the Debentures to be bifurcated into its debt and equity components, however IFRS required the fair value of the debt component to be based on a similar stand-alone instrument with the difference between the face value and the fair value of the debt component being allocated to the equity component. Under IFRS, the liability must be fair valued with the residual assigned to the equity component. Under Canadian GAAP the value of the \$48,785,344 (C\$49,000,000) Debentures assigned to equity amounted to \$25,094,610 with the balance at March 4, 2008 of \$23,690,735 allocated to debt. This amount was being accreted to the full face value of the Debentures over the term of the Debentures. Under IFRS, the amount allocated to debt has been initially estimated to be \$40,633,200 with the balance of \$8,152,140 allocated to equity. The debt component will be accreted to the face value of the Debentures retrospectively from March 4, 2008. The impact to the Company's financial statements at January 1, 2010 is currently being calculated.

Deferred income taxes: The bifurcation of the equity component results in a difference of \$8,152,140 between the tax basis of the debt and its accounting basis. This difference meets the definition of a taxable temporary difference under IAS 12 Income Taxes and there is no exception from recording deferred taxes in respect of compound financial instruments as there is under Canadian GAAP. Under IAS 12 paragraph 23, the deferred taxes are charged to equity on initial recognition. However, subsequent changes to the deferred tax liability (i.e. the reduction in the deferred tax liability created as the debt accretes to its principal amount) are charged to income.

Property, plant and equipment (PP&E) – This includes oil and gas assets in the development and production phases. As all of our oil and gas assets are in the development and production phases, the full amount will be included in PP&E and allocated to one cash generating unit (CGU) as of January 1, 2011.

Depletion expense – On transition to IFRS, we have the option to use either proved reserves or proved plus probable reserves in the depletion calculation. The Company expects to use proved reserves in determining depletion expense.

Provisions – The major difference between the current Canadian standard and IFRS is the discount rate used to measure the Company's reclamation liabilities ("asset retirement obligations" or "ARO" under Canadian GAAP) Under the current Canadian standard, a credit adjusted risk free rate is used, whereby the IFRS allows the use of a risk free rate when risks are factored into the expected cash flows. A lower discount rate will increase the ARO liability and on transition to IFRS, the corresponding impact will be charged to retained earnings or deficit.

In addition to the accounting policy differences, the Company's transition to IFRS will impact the internal controls over financial reporting, the disclosure controls and procedures and information technology (IT) systems as follows:

Internal controls over financial reporting – Based on our accounting policies under IFRS, we have identified certain additional controls and changes in procedures that are required. We do not consider these changes to be significant.

Disclosure controls and procedures – Throughout the transition process, we will be assessing stakeholder's information requirements and will ensure that adequate and timely information is provided while ensuring the Company maintains its due process regarding information that is disclosed.

IT Systems – We have assessed the readiness of our accounting software and will continue to assess other system requirements that may be needed in order to perform ongoing calculations and analysis under IFRS. These changes are not considered to be significant.

Training and communication - Key employees involved with implementation have completed training throughout the past two years. Policy decisions are being communicated to individuals affected and additional training is being provided as required.

Business Impacts - Adoption of IFRS is not expected to have a material impact on current contracts. Analysis of taxation impacts is currently underway by individuals experienced with taxation and a full evaluation will be completed in the first quarter of 2011.

## **Risk Factors**

Exploration, Development and Production Risks: Oil and natural gas exploration involves a high degree of risk. There is no assurance that expenditures made on exploration by us will result in new discoveries of oil or natural gas in commercial quantities. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties associated with drilling in unknown formations, and other factors such as the costs associated with encountering various drilling conditions for example: drilling over pressured zones, tools lost in the hole, and changes in drilling plans and locations.

The long-term commercial success of our company as an oil and gas producer depends largely on our ability to find, acquire, develop and commercially produce oil and natural gas reserves. No assurance can be given that we will be able to locate satisfactory properties for acquisition or participation, that we will be able to obtain financing for further exploration and development, or that we will find oil or natural gas on our properties.

Our business plan is to generate profitable growth, measured by growth in production, proved reserves, and cash flow from operations. To accomplish this, we plan to focus on development of our Pinedale property assets, specifically the Mesa and Warbonnet properties and accordingly, subsequent to December 31, 2010, we have sold our Wainwright property in Alberta, Canada and allowed our CRB properties to expire.

Management will continue to evaluate prospects on an ongoing basis in a manner consistent with industry standards and corporate policies. The long-term commercial success of our company as a junior oil and gas producer depends on, among other things, our ability to find, acquire, develop and commercially produce oil and natural gas reserves. No assurance can be given that we will be able to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, we may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that we will be able to obtain financing for further exploration and development, if at all. In this regard, we have not entered into any contracts relating to the acquisition or participation in any properties other than as set forth herein nor have any letters of intent been executed.

We also face the risk of engaging in unprofitable efforts, as we may drill wells which are productive, but do not produce sufficient net revenues to return a profit after drilling, operating and other costs and we may also drill dry wells. The cost of operations may also be increased by drilling hazards, environmental damages and various field operating conditions. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions,

insufficient storage or transportation capacity or other geological and mechanical conditions. While close well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

In addition, oil and gas operations are subject to inherent risks associated with the exploration, development and production of oil and natural gas properties. Such risks include encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, sour gas releases, fires, spills, power outages, labour disruptions and inability to obtain suitable or adequate machinery, equipment or labour. Losses resulting from the occurrence of any of these risks could have a materially adverse effect on future results of operations, liquidity and financial condition of our company.

Prices, Markets and Marketing of Crude Oil and Natural Gas: Our financial position and prospects are affected by, among other things, the price of oil and gas, which is determined largely by global supply and demand. A material decline in oil and gas prices could result in a reduction of net production revenue for our company, at which point one or more of our projects could become uneconomic, possibly leading to a reduction in volume of our oil and gas reserves. We may also elect not to produce from certain wells at lower prices. This could result in a material decrease in our future net production revenue, causing a reduction in our oil and gas acquisition and/or development activities. A substantial material decline in oil and gas prices could limit or reduce our borrowing base, reducing the bank credit available to us and possibly requiring us to repay a portion or all of any existing bank debt.

We are also affected by our ability to market our oil and natural gas to prospective buyers. Marketability is affected by numerous factors beyond our control. The marketability and price of oil and natural gas which may be acquired or discovered by us will be affected by numerous factors beyond our control. We will be affected by the differential between the price paid by refiners for light quality oil and the grades of any oil produced by us. Our ability to market any natural gas we produce may depend upon our ability to acquire space on pipelines which deliver natural gas to commercial markets. We may also be affected by deliverability uncertainties related to the proximity of our reserves to pipelines and processing facilities, and also related to operational problems with such pipelines and facilities and extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business. We have limited direct experience in the marketing of oil and natural gas.

Substantial Capital Requirements and Liquidity: We anticipate substantial future capital expenditures for the exploration, development and production of oil and natural gas reserves. We may not be able to secure the required capital to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet our capital requirements or to fund our ongoing activities at all times, which could have a potential material adverse effect on our financial condition, results of operations and prospects. We may require additional financing from time-to-time to carry out our oil and gas acquisitions, exploration and development activities. It is possible that such financing will not be available or, if available, will not be available on favourable terms. Failure to obtain such financing on a timely basis could cause us to forfeit our interest in certain properties, miss certain acquisition opportunities and reduce or terminate our operations. We may choose to sell additional securities in our capital stock to finance proposed operations. If this occurs, existing shareholders will experience a dilution of their equity interest in our company.

Risk of Foreign Operations: Our key oil and gas producing operations and assets are located in the United States. As a result, they are subject to political, economic and other uncertainties for reasons, including, but not limited to:

- (a) changes in energy policies or the personnel administering them;
- (b) expropriation of property without fair compensation;
- (c) cancellation or modification of contract rights;
- (d) foreign exchange restrictions;
- (e) currency fluctuations;
- (f) royalty and tax increases and other risks arising out of foreign governmental sovereignty over the areas in which our operations are conducted; and
- (g) risks of loss due to civil strife and acts of war.

Certain of our operations may also be adversely affected by laws and policies of Canada affecting foreign trade, taxation and investment. In the event of a dispute arising in connection with our foreign operations, we may be subject to the exclusive jurisdiction of foreign courts or, in the alternative, we may not be successful in subjecting foreign persons to the jurisdiction of courts in Canada or enforcing Canadian judgements in such other jurisdictions. We may also be hindered or prevented from enforcing our rights with respect to a governmental instrumentality because of the doctrine of sovereign immunity. In addition, our existing enterprises were formed pursuant to, and our operations are governed by, a number of legal and contractual relationships. The effectiveness of, and enforcement of our contracts and relationships with parties in these jurisdictions cannot be assured. Consequently, our foreign exploration, development and production activities could be substantially affected by factors beyond our control, any of which could have a material adverse effect on our company and our business.

Property Defects: Although we have obtained title reports with respect to some of our properties, we have not obtained title reports with respect to all of our current properties. In addition, the title reports that we have obtained are many years old. Title reports are not title insurance and they do not act as a guarantee of title. Our properties may be subject to encumbrances such as prior unregistered agreements, native land claims or transfers which have not been recorded or detected through title research or which have been asserted since the date the research was completed. Additionally, the land upon which we hold leases may not have been surveyed; therefore, the precise area and location of such interests may be subject to challenge.

In addition to the foregoing, we hold title to all of our US properties in the name of our subsidiaries.

In 2006, our wholly-owned subsidiary, Arrowhead, and seven other unrelated defendants were served with a lawsuit alleging that certain properties, including some of the properties owned by Arrowhead, are subject to a 5% net profits interest owned by the plaintiffs and that all of the defendants, including Arrowhead, are in default of their obligations under this 5% net profits interest to pay money to the plaintiffs. Arrowhead leases that are encumbered by this lawsuit consist of five Warbonnet leases totalling 2,040 gross acres (867 net acres) and at the time, 13 developed wells (5.5 net). This claim is described in detail under Contingent Liabilities on page 7.

Financial Considerations: We will require substantial funds to bring any oil and gas deposits contained on our properties into production. The decision to move into production will involve consideration and evaluation of several significant factors including but not limited to: (1) results of exploration programs; (2) costs of bringing a property into production, including exploration and development work, preparation of production feasibility studies, and construction of production facilities; (3) availability and costs of financing; (4) ongoing costs of production; (5) market prices for the oil and gas to be produced; (6) environmental compliance regulations and restraints; and (7) political climate, governmental regulation and control. Many of the factors taken into consideration are beyond our control and may have a material effect on the outcome of our decision.

Environmental Risks and Permits and Licenses: All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of domestic and international laws. Compliance with applicable environmental legislation may require significant expenditures and a breach of such legislation may result in the imposition of fines and penalties, some of which may be material. We may also incur remediation costs. The trend in environmental legislation is toward the application of stricter standards and enforcement, and larger fines and liability, resulting in potentially increased capital expenditures and operating costs to our company. No assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect our financial condition, results of operations or prospects.

Our operations may require permits and licenses, including environmental permits and licenses, from various governmental and regulatory authorities. There can be no assurance that we will be able to obtain all necessary permits and licenses for our projects.

Reliance on Operators and Key Employees: We are not the operator of our current oil and gas properties and may not be the operator of future oil and gas properties. To the extent that we are not the operator, we are dependent on others for the timing of activities related to such properties. We are largely unable to direct or control the activities of the operators.

Our success is also largely dependent upon the performance of management and the hired management consulting company. We do not have any 'key man' insurance. The loss of service of any director or officer, as well as the hired management consultant company could have a materially adverse effect on us.

Management: Our success is currently largely dependent on the performance of our directors and officers. The loss of services of any of these persons could have a materially adverse effect on our business and prospects. There is no assurance we can maintain the services of our directors, officers or other qualified personnel required to operate our business.

Additional Funding Requirements: Our cash flow from our reserves may not be sufficient to fund our ongoing activities at all times. From time-to-time, we may require additional financing in order to carry out our oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause us to forfeit our interests in certain properties, miss certain acquisition opportunities and reduce or terminate our operations. If our revenues from our reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect our ability to expend the necessary capital to replace our reserves or to maintain our production. If our cash flow from operations is not sufficient to satisfy our capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or available on favourable terms.

Insurance: We may be subject to liability as a result of our involvement in the oil and gas exploration and development of our daily operations. Although we may obtain insurance in accordance with industry standards to address such risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not, in all circumstances, be insurable or, in certain circumstances, we may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of such uninsured liabilities would reduce the funds available to us. We could face material adverse effects on our financial position, results of operations or prospects if an event occurs which could expose us to significant liability.

Reserve Replacement: Our future oil and natural gas reserves, production, and cash flows are highly dependent on the successful acquisition or discovery of new reserves, as our existing reserves will decline over time as they are exploited. Without the continual addition of new reserves, we may be adversely affected. A future increase in our reserves will depend not only

on our ability to develop any properties we may have from time-to-time, but also on our ability to select and acquire suitable producing properties or prospects. There can be no assurance that our future exploration and development efforts will result in the discovery and development of additional commercial accumulations of oil and natural gas.

Currency Fluctuations: We are subject to currency fluctuations as we maintain our deposit accounts in US and Canadian currencies and maintain operations mainly in the USA. Currency fluctuations could materially affect our financial position and results.

Growth Management: We could experience rapid growth in production, revenues, personnel, complexity of administration and in other areas. There can be no assurance that we will be able to manage the impact that future growth could place on our administrative infrastructure, systems, finances and internal controls. If we fail to manage growth effectively, it may have a material adverse effect on our business, operation results and financial condition.

Dividends: We intend to retain any future earnings to finance the development and expansion of our business. We do not anticipate paying any cash dividends on our common stock in the near future. The declaration, payment and amount of any future dividends will be made at the discretion of the board of directors, and will depend upon, among other things, the results of operations, cash flows and financial condition, operating and capital requirements, and other factors as the board of directors considers relevant. There is no assurance that future dividends will be paid, and if dividends are paid, there is no assurance with respect to the amount of any such dividend. Unless we pay dividends, our shareholders will not be able to receive a return on their shares unless they sell them.

Corporate Matters: Certain of our directors and officers are involved in managerial and/or director positions of other oil and gas companies, partnerships or other entities involved in natural resource exploration and development, and conflicts of interest may arise between their duties as officers, managers or directors of our company and as officers and directors of these other companies, partnerships or other entities. Conflicts must be disclosed in accordance with, and are subject to such other procedures and remedies as apply under the British Columbia *Business Corporations Act* and applicable securities law.

Conflicts of Interest: Some of the directors and officers are engaged and will continue to be engaged in the search for additional business opportunities on behalf of other corporations, and situations may arise where these directors and officers will be in direct competition with us. Conflicts, if any, will be dealt with in accordance with the relevant provisions of the British Columbia *Business Corporations Act* and applicable securities law. In order to avoid any possible conflict of interest which may arise between our directors' duties to our company and their duties to the other companies on whose boards they serve, our directors and officers have agreed to the following:

- (1) participation in other business ventures offered to the directors will be allocated between the various companies and on the basis of prudent business judgement and the relative financial abilities and needs of the companies to participate;
- (2) no commissions or other extraordinary consideration will be paid to such directors and officers; and
- (3) business opportunities formulated by or through other companies in which the directors and officers are involved will not be offered to us except on the same or better terms than the basis on which they are offered to third party participants.

Issuance of Debt: We may enter into transactions to acquire assets or the shares of other corporations. These transactions may be financed partially or wholly with debt, which may increase our debt levels above industry standards. Our articles do not limit the amount of

indebtedness that we may incur. The level of our indebtedness could impair our ability to obtain additional financing in the future or on a timely basis necessary to take advantage of business opportunities that may arise.

Availability of Drilling Equipment and Access Restrictions: Our exploration and development activities are dependent on the availability of drilling and related equipment in the particular areas where such activities will be conducted and the proximity of pipelines or other transmission facilities. Demand for such limited equipment or access restrictions may affect the availability of such equipment and facilities to us and may delay exploration and development activities.

### **Risks Relating to the Industry**

The oil and gas industry is subject to extensive controls and regulations imposed by various levels of government. Outlined below are some of the more significant aspects of the legislation, regulations and agreements governing the oil and gas industry. All current legislation is a matter of public record and we are unable to predict what additional legislation or amendments may be enacted.

Potential Profitability of Oil and Gas Ventures Depends upon Factors beyond our Control: The potential profitability of oil and gas properties is dependent upon many factors that are beyond our control. World prices and markets for oil and gas are unpredictable, highly volatile, potentially subject to governmental fixing, pegging, controls, or any combination of these and other factors, and respond to changes in domestic, international, political, social, and economic environments. Additionally, due to worldwide economic uncertainty, the availability and cost of funds for production and other expenses have become increasingly difficult, if not impossible, to project. These changes and events may materially affect our financial performance.

A productive well may become uneconomic or unmarketable in the event water or other deleterious substances are encountered which impair or prevent the production of oil and/or gas from the well. The marketability of oil and gas that we may acquire or discover could be affected by numerous factors beyond our control. These factors include the proximity and capacity of pipelines and processing equipment, market fluctuations of prices, taxes, royalties, land tenure, allowable production, adverse weather conditions and environmental protection. The extent of these factors cannot be accurately predicted and the combination of these factors may result in our company not receiving an adequate return on invested capital.

Competition in the Oil and Gas Industry: We will actively compete for reserve acquisitions, exploration leases, licenses and concessions and skilled industry personnel with a substantial number of other oil and gas companies, some of which may have significantly greater technical, financial, operational resources and personnel. Our competitors include major integrated oil and natural gas companies and numerous other independent oil and natural gas companies and individual producers and operators.

Certain of our natural gas customers and potential customers may themselves be exploring for oil and natural gas, and the results of these exploration efforts could affect our ability to sell or supply oil or gas to these customers in the future. Our ability to successfully bid on and acquire additional property rights, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with customers will be dependent upon developing and maintaining close working relationships with our industry partners and joint operators and our ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment.

Fluctuating Price and Demand: The marketability of natural resources that we may acquire or discover may be affected by numerous factors beyond our control. These factors include market fluctuations in oil and gas pricing and demand, the proximity and capacity of natural

resource markets and processing equipment, governmental regulations, land tenure, land use, regulation concerning the importing and exporting of oil and natural gas and environmental protection regulations. The impact of these factors cannot be accurately predicted, but the combination of these factors could have an adverse impact on our business.

Comprehensive Regulation of the Oil and Gas Industry: Our operations are subject to federal, provincial or state and local laws relating to the protection of the environment, including laws regulating removal of natural resources from the ground and the discharge of materials into the environment. Our operations are also subject to federal, provincial or state and local laws and regulations that seek to maintain health and safety standards by regulating the design and use of drilling methods and equipment. Various permits from government bodies are required for drilling operations to be conducted; no assurance can be given that such permits will be received. We can give no assurance that environmental standards imposed by federal, provincial, state or local authorities will not be changed or that any such changes would not have materially adverse effects on our activities. Moreover, compliance with such laws may cause substantial delays or require capital outlays in excess of those anticipated, thus causing an adverse effect on our business and our company. Additionally, we may be subject to liability for pollution or other environmental damages, which we may elect not to insure against due to, among other reasons, prohibitive premium costs.

Environmental Regulations: In general, our exploration, development and production activities are subject to certain federal, provincial or state and local laws and regulations relating to environmental quality and pollution control. These laws and regulations increase the costs of these activities and may prevent or delay the commencement or continuance of a given operation. Specifically, we are subject to legislation regarding emissions into the environment, water discharges and storage and disposition of hazardous wastes. In addition, legislation has been enacted which requires well and facility sites to be abandoned and reclaimed to the satisfaction of state authorities. However, such laws and regulations are frequently changed and we are unable to predict the ultimate cost of compliance. Our operating partners maintain insurance coverage customary to the industry; however, we are not fully insured against all environmental risks.

Government Regulation/Administrative Practice: There is no assurance that the laws, regulations, policies or current administrative practices of any government body, organization or regulatory agency in Canada, the United States or any other applicable jurisdiction will not be changed, applied or interpreted in a manner which will fundamentally alter our ability to develop, operate, export or market our products. The actions, policies or regulations, or changes thereto, of any government body or regulatory agency, or other special interest groups, may have a detrimental effect on our company. Any or all of these situations may have a negative impact on our ability to operate and make a profit.

Future Sales of Common Shares by Existing Shareholders: Sales of a large number of Common Shares in the public markets, or the potential for such sales, could decrease the trading price of the Common Shares and could impair our ability to raise capital through future sales of Common Shares.

## **Other MD&A Requirements**

### **Uncertainty of Estimates of Reserves**

Under applicable regulatory requirements, we will be required to identify and disclose as proved oil and gas reserves, estimated quantities of crude oil, natural gas and natural gas liquids. This geological and engineering data demonstrates with reasonable certainty the estimated quantities of crude oil, natural gas and natural gas liquids, which will be recoverable in future years from known reservoirs under existing economic and operating conditions. However, the process of estimating oil and gas reserves is complex, requiring significant

decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir, and as a result, such estimates are inherently imprecise. Actual future production, oil and gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves may vary substantially from our estimations from year to year. Any significant variance in the assumptions could materially affect the estimated quantities and present values of reserves. For example, a material drop in oil and gas prices, or a material increase in applicable taxes, will require management to reassess whether known reservoirs can continue to be reasonably judged as economically productive from one year to the next. In addition, the reserves may be subject to downward or upward revisions based upon production history, results of future exploration and development, prevailing oil and gas prices and other factors, many of which are beyond our control. Actual production, revenues, taxes, development expenditures and operating expenses with respect to the reserves will likely vary from the estimates presented herein, and such variances may be material.

### Declining Reserves

In general, production rates from oil and gas properties decline as reserves are depleted. The decline rates depend on reservoir characteristics and vary from steep declines to the relatively slow declines characteristic of long-lived fields in other regions. Should one or more of the above risks materialize or should Bucking Horse's underlying assumptions prove incorrect, their actual results may materially differ from our current expectations. Therefore, in evaluating forward-looking statements, readers should specifically consider the various factors that could cause our actual results to materially differ from such forward-looking statements.

### Reserves Data and Other Oil and Gas Information

Our independently prepared reserves assessment and evaluation of oil and gas properties effective December 31, 2010 have been prepared in accordance with mandated National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities of Canadian Securities Administrators. A summary of our reports is available on SEDAR at [www.sedar.com](http://www.sedar.com).

### Outstanding Share Data

We are a publicly traded company and our Common Shares are listed for trading on the TSX under the symbol BUC.

As of December 31, 2010, we had the following securities outstanding:

Class of Shares	Par Value	Number Authorized	Number Issued
Common	Nil	Unlimited	22,690,413

Security Type	Number Outstanding	Exercise/Conversion Price	Expiry Date
Convertible Debenture <sup>(1)</sup>	2 <sup>(1)</sup>	C\$4.875 per unit <sup>(1)</sup>	March 14, 2018
Convertible Debenture <sup>(2)</sup>	2 <sup>(2)</sup>	C\$4.000 per unit <sup>(2)</sup>	August 4, 2014
Convertible Debenture <sup>(3)</sup>	2 <sup>(3)</sup>	C\$4.875 per unit <sup>(3)</sup>	March 14, 2018

As of the date of this MD&A, we had the following securities outstanding:

Class of Shares	Par Value	Number Authorized	Number Issued
Common	Nil	Unlimited	22,683,513

Security Type	Number Outstanding	Exercise/Conversion Price	Expiry Date
Convertible Debenture <sup>(1)</sup>	2 <sup>(1)</sup>	C\$4.875 per unit <sup>(1)</sup>	March 14, 2018
Convertible Debenture <sup>(2)</sup>	2 <sup>(2)</sup>	C\$4.000 per unit <sup>(2)</sup>	August 4, 2014
Convertible Debenture <sup>(3)</sup>	2 <sup>(3)</sup>	C\$4.875 per unit <sup>(3)</sup>	March 14, 2018

Please see "Capital Resources" section (Page 10) for terms of the Debentures. As at December 31, 2011, the principal amount of the debentures outstanding amounted to \$49,266,000 (C\$49,000,000)

(1) On March 4, 2008, we issued the First Debentures to each of the Debenture Lenders. Each of the First Debentures is in the principal amount of \$9,551,579 (C\$9,500,000), has a term of ten years, earns interest initially at a rate of 10% during the first six years and 15% and is convertible into units during the first five years at a conversion price of C\$4.875 per unit. Each unit consists of one Common Share one share purchase warrant, which entitled the holder to purchase one additional Common Share for C\$4.875 until the fifth anniversary of the date of issuance, at which date these share purchase warrants will expire. Effective May 16, 2008, as a result of an interest rate acceleration provision, the interest rate applicable to the First Debentures increased from 10% to 15%.

(2) On March 4, 2008, we issued the Second Debentures to each of the Debenture Lenders. Each of the Second Debentures is in the principal amount of \$5,027,147 (C\$5,000,000), has a term of ten years from August 4, 2004. Interest is payable monthly at a rate initially of 10% per annum for the first six years of the term and at a rate of 15% during the last four years. All or any portion of the amount outstanding under these Second Debentures from time-to-time is convertible into units at the option of the holder at a price of C\$4.00 per unit. Upon conversion, each unit consists of one Common Share and one non-transferable share purchase warrant, which has expired with no warrants being exercised. Effective May 16, 2008, as a result of an interest rate acceleration provision, the interest rate applicable to the Second Debentures increased from 10% to 15%.

(3) On March 4, 2008, we issued the Third Debentures to each of the Debenture Lenders. Each of the Third Debentures is in the principal amount of \$10,054,293 (C\$10,000,000), has a term of ten years, earns interest at a rate initially of 10% during the first six years and 15% during the last four years and is convertible into units during the first five years at a conversion price of C\$4.875 per unit. Each unit consists of one Common Share and one share purchase warrant, which entitled the holder to purchase one additional Common Share for C\$4.875 until the fifth anniversary of the closing date, at which date the share purchase warrants will expire. Effective May 16, 2008, as a result of an interest rate acceleration provision, the interest rate applicable to the Third Debentures increased from 10% to 15%.

There are no Common Shares held in escrow and no Common Shares are subject to pooling.

### **Disclosure Controls and Procedures and Internal Control Over Financial Report**

Disclosure Controls and Procedures: Our Chief Executive Officer and Chief Financial Officer (the "Responsible Officers") are responsible for establishing and maintaining disclosure controls and procedures for our company, designed to provide reasonable assurance that material information relating to our company and our subsidiaries is made known to the Responsible Officers by others within the organization, particularly during the period in which our quarterly and year-end financial statements and MD&A are being prepared. The Responsible Officers have evaluated the effectiveness of our disclosure controls and procedures as defined in National Instrument 52-109 - *Certification of Disclosure In Issuers' Annual and Interim Filings* ("NI 52-109") as at December 31, 2010. Based on this evaluation, they have concluded that such controls and procedures are effective in conveying the required information to the Responsible Officers, particularly in light of the our size, structure and stage

of development. Management is currently in the process of formalizing the disclosure controls and procedures. These controls and procedures, no matter how well conceived or operated, can provide only reasonable, not absolute assurance, that the objectives are met.

Internal Controls Over Financial Reporting: Our Responsible Officers are responsible for establishing and maintaining internal controls and procedures for us, designed to provide reasonable assurance that material information relating to our company and our subsidiaries is made known to the Responsible Officers by others within the organization, particularly during the period in which our quarterly and year-end financial statements and MD&A are being prepared. The Responsible Officers have evaluated the effectiveness of our internal controls and procedures as defined in NI 52-109 as at December 31, 2010. Based on this evaluation, except for the control weakness described below, they have concluded that such controls and procedures are effective in conveying the required information to the Responsible Officers, particularly in light of our size, structure and stage of development. Management is currently in the process of formalizing the internal controls and procedures. These internal controls and procedures, no matter how well conceived or operated, can provide only reasonable, not absolute assurance, that the objectives are met. Management is aware that in-house expertise to deal with complex taxation, accounting and reporting issues may not be sufficient. We utilize outside assistance and advice on complex financial, taxation and reporting issues, which is common with companies of a similar size. We have assessed the design of our internal control over financial reporting and during this process we identified potential weaknesses in internal controls over financial reporting which are as follows:

- Due to the limited number of staff at our company it is not feasible to achieve complete segregation of incompatible duties. We have mitigated this weakness in controls by adding management review procedures over the areas where segregation is an issue.
- We do not retain staff with specialized and current income tax, financial reporting and complex accounting expertise. We report current and future income tax expenses and liabilities and other complex accounting calculations based on management's estimates and rely on reviews by management, external consultants and audit committee for quality assurance.

There have been no significant changes to the internal controls in this period. As a result of our assessment of the design of our internal control over financial reporting, we conclude that there is only a remote likelihood that a material misstatement would not be prevented or detected. Management and the board of directors work to mitigate the risk of a material misstatement in financial reporting; however, there can be no assurance that this risk can be reduced to less than a remote likelihood of a material misstatement.

### **Additional Information**

Additional information relating to our company, including periodic quarterly unaudited consolidated financial statements, audited annual consolidated financial statements and the annual information form for the fiscal year ended December 31, 2010, is available on SEDAR at [www.sedar.com](http://www.sedar.com). We also maintain a website at [www.buckinghorsenergy.com](http://www.buckinghorsenergy.com). Information can also be obtained by contacting us by mail at #900 – 609 West Hastings Street, Vancouver, British Columbia, V6B 4W4 or by telephone at (604) 331-3398.