EAGLEFORD ENERGY INC

(Formerly: Eugenic Corp.)

Management's Discussion and Analysis of Financial Condition and Operating Results

For the period ended
November 30, 2010

(Expressed in Canadian Dollars)

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The following Management's Discussion and Analysis of Financial Condition and Operating Results of Eagleford Energy Inc. ("Eagleford" or the "Company") should be read in conjunction with the Company's Unaudited Consolidated Financial Statements for the period ended November 30, 2010 and the Audited Consolidated Financial Statements for the years ended August 31, 2010 and 2009 and notes thereto stated in Canadian dollars. The results herein have been prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). This Management's Discussion and Analysis is dated January 21, 2011 and has been approved by the Board of Directors of the Company.

The following Management's Discussion and Analysis ("MD&A") may contain forward-looking statements. Forward-looking statements are based on current expectations that involve a number of risks and uncertainties, which could cause actual events or results to differ materially from those reflected herein. Forward-looking statements are based on the estimates and opinions of management of the Company at the time the statements were made. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe", and similar expressions. Information concerning reserve estimates and capital cost estimates may also be deemed as forward-looking statements as such information constitutes a prediction of what might be found to be present and how much capital will be required if and when a project is actually developed. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements (see Risks and Uncertainties below).

Certain measures in this Management Discussion and Analysis of Financial Condition and Operating Results do not have any standardized meaning as prescribed by Canadian generally accepted accounting principles such as netback and other production figures and therefore are considered non-GAAP measures. Therefore these measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in order to provide shareholders and potential investors with additional information regarding the Company's liquidity and its ability to generate funds to finance its operations.

Our Canadian public filings can be accessed and viewed via the System for Electronic Data Analysis and Retrieval ("SEDAR") at www.sedar.com. Readers can also access and view our Canadian public insider trading reports via the System for Electronic Disclosure by Insiders at www.sedi.ca. Our U.S. public filings are available at the public reference room of the U.S. Securities and Exchange Commission ("SEC") located at 100 F Street, N.E., Room 1580, Washington, DC 20549 and at the website maintained by the SEC at www.sec.gov.

GLOSSARY OF ABBREVIATIONS

Bbl	barrel
Bbl/d	barrels per day
Boe	barrels of oil equivalent (1)
Boe/d	barrels of oil equivalent per day
Mcf	1,000 cubic feet of natural gas
Mcf/d	1,000 cubic feet of natural gas per day

(1) Boe conversion ratio of 6 Mcf: 1Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Disclosure provided herein in respect of Boes may be misleading, particularly if used in isolation.

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

To Convert From	To	Multiply By
Mcf	Cubic metres	28.317
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls	6.292

Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometers	1.609
Kilometers	Miles	0.621
Acres (Alberta)	Hectares	0.405
Hectares (Alberta)	Acres	2.471

OVERVIEW

Eagleford Energy Inc. is incorporated under the laws of the Province of Ontario, and is registered as an extra-provincial company in Alberta. The Company is a reporting issuer with the United States Securities and Exchange Commission and the Company's common shares trade on the Over-the-Counter Bulletin Board (OTCBB) under the symbol EFRDF.

The Company's operations consist of a 0.5% Non Convertible Overriding Royalty in a natural gas well located in Haynes, Alberta, Canada a 5.1975% working interest in a natural gas unit located in Alberta, Canada, an 85% working interest before payout (69% working interest after payout) in Matthews lease comprising 2,629 gross acres of land in Zavala County, Texas. In addition, the Company holds a 100% working interest in the Murphy lease comprising approximately 2,637 acres of land in Zavala County, Texas subject to a 10% carried interest on the drilling costs from surface to base of the Austin Chalk formation, and a 3% carried interest on the drilling costs from the top of the Eagle Ford shale formation to basement on the first well drilled into a serpentine plug and for the first well drilled into a second serpentine plug, if discovered. The Company also holds a 0.3% net smelter return royalty on eight mining claims located in Red Lake Ontario which is carried on the Consolidated Balance Sheets at $Nil.

The Company's Unaudited Consolidated Financial Statements for the period ended November 30, 2010 and 2009 include the accounts of the Company, its wholly owned subsidiaries 1354166 Alberta Ltd. from the date of acquisition, February 27, 2009 and Dyami Energy from the date of acquisition August 31, 2010.

On November 12, 2009, the Company's wholly owned subsidiary 1406768 Ontario Inc. changed its name to Eagleford Energy Inc. On November 30, 2009 the Company amalgamated with Eagleford Energy Inc. and upon the amalgamation the entity's new name became Eagleford Energy Inc.

OVERALL PERFORMANCE

Revenue for the three months ended November 30, 2010 was down $9,159 to $17,099 compared to $26,258 for the same period in 2009. The decrease in revenue is attributed to lower production volumes and lower commodity prices received. Net loss and comprehensive loss for the three months ended November 30, 2010 was $98,992 compared to $80,299 for the comparable three month period in 2009. The increase in loss during 2010 was primarily related to increases in administrative expenditures offset partially offset by an expense recovery and foreign exchange gains.

For the three months ended November 30, 2010 the Company's cash position increased by $229,258 to $273,034 compared to cash of $43,776 at August 31, 2010. At November 30, 2010 the Company's accounts receivable was $107,026 representing an increase of $53,966 compared to $53,060 at August 31, 2010. For the three months ended November 30, 2010 current liabilities increased by $1,995,701 to $2,823,385 compared to $842,424 at August 31, 2010. The Company has a working capital deficiency of $2,458,064 at November 30, 2010 compared to a working capital deficiency of $744,262 at August 31, 2010.

During the three month period ended November 30, 2010, 1,100,000 common share purchase warrants were exercised at $0.07 for proceeds of $77,000.

During the three month period ended November 30, 2010 the Company received US$1,450,000 and CDN$149,000 and issued promissory notes bearing interest at 10% per annum. Interest is payable annually on the anniversary date of the notes.

Through Dyami Energy, the Company commenced operations in August 2010 to drill an initial Eagle Ford shale test well on the Matthews Lease in Zavala County, Texas. The Matthews/Dyami #1H well was spud in on October

15, 2010 and was drilled to a measured depth of 8,563, feet which includes a 3,300 foot "in section" lateral into the Eagle Ford shale formation. A shot point sleeve was installed in the Eagle Ford shale formation to protect the well bore and facilitate a multi stage frac completion.

The well was logged extensively and 36 sidewall cores were taken from 4 key formations in descending order, the San Miguel, the Austin Chalk, the Eagle Ford and the Buda. The logs were interpreted by Weatherford International Ltd and the sidewall cores were analyzed by Core Laboratories and Weatherford and based on those results the Company is formulating a detailed frac design and completion plan for the Dyami/Matthews #1 H well. For the three months ended November 30, 2010 the Company incurred $1,627,606 in expenditures related to the Matthews/Dyami #1H well.

The Company expects to apply additional capital to further enhance our property interests. As part of the Company's oil and gas development program, management of the Company anticipates further expenditures to expand its existing portfolio of proved reserves. Amounts expended on future exploration and development is dependent on the nature of future opportunities evaluated by the Company. These expenditures could be funded through cash held by the Company or through cash flow from operations. Any expenditure which exceeds available cash will be required to be funded by additional share capital or debt issued by the Company, or by other means. The Company's long-term profitability will depend upon its ability to successfully implement its business plan.

The Company's past primary source of liquidity and capital resources has been loans and advances, cash flow from oil and gas operations and proceeds from the sale of marketable securities and from the issuance of common shares.

RISK AND UNCERTAINTIES

The Company's producing wells are subject to normal levels of decline and unavoidable changes in operating conditions in facilities operated by third parties. There is an existing and available market for the oil and gas produced from the properties. However, the prices obtained for production are subject to market fluctuations, which are affected by many factors, including supply and demand. Numerous factors beyond our control, which could affect pricing include:

- volatility in market prices for oil and natural gas;
- the level of consumer product demand;
- weather conditions;
- the foreign supply of oil and gas;
- the price of foreign imports; and
- ability to raise financing;
- reliance on third party operators;
- ability to find or produce commercial quantities of oil and natural gas;
- liabilities inherent in oil and natural gas operations;
- dilution of interests in oil and natural gas properties;
- general business and economic conditions;
- the ability to attract and retain skilled staff;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, financings, acquisitions of reserves, undeveloped lands and skilled personnel; and
- government regulation and environmental legislation.

The Company cautions that the foregoing list of important factors is not exhaustive. Investors and others who base themselves on the Company's forward-looking statements should carefully consider the above factors as well as the uncertainties they represent and the risk they entail. The Company also cautions readers not to place undue reliance on these forward-looking statements. Moreover, the forward-looking statements may not be suitable for establishing strategic priorities and objectives, future strategies or actions, financial objectives and projections other than those mentioned above. (For additional risk factors, please see the Company's Annual Information Form filed on Form 20F).

Financial Instruments and Risk Factors

The Company is exposed to financial risk, in a range of financial instruments including cash, accounts receivable and accounts payable and income taxes payable and loans payable. The Company manages its exposure to financial risks by operating in a manner that minimizes its exposure to the extent practical.

The main financial risks affecting the Company are discussed below.

The fair value of financial instruments at November 30, 2010 and August 31, 2010 is summarized as follows:

	November 30, 2010		August 31,2010	
	Amount	**Fair Value**	Amount	Fair Value
Financial assets				
Held for trading				
Cash and cash equivalents	**$ 273,034**	**$ 273,034**	$ 43,776	$ 43,776
Loans and receivables				
Accounts receivable	**$ 107,026**	**$ 107,026**	$ 53,060	$ 53,060
Due from related party	**$ -**	**$ -**	$ 1,325	$ 1,325
Financial liabilities				
Accounts payable	**$ 853,725**	**$ 843,725**	$ 488,741	$ 488,741
Loan payable	**$ 110,000**	**$ 110,000**	$ 110,000	$ 110,000
Shareholder loans	**$ 1,694,780**	**$ 1,531,052**	$ 57,500	$ 57,500
Secured notes payable	**$ 1,164,964**	**$ 1,096,862**	$ 1,207,527	$ 1,145,289

Credit Risk

Credit risk is the risk of a financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligation and arises principally from joint venture partners and natural gas and oil marketers. The Company is exposed to credit risk in respect to its cash and cash equivalents and accounts receivable.

Cash and cash equivalents are held in operating accounts with highly rated Canadian banks and therefore the Company considers these assets to have negligible credit risk.

Receivables from petroleum and natural gas marketers are normally collected on the 25th day of the month following production. The Company historically has not experienced any collection issues with its petroleum and natural gas marketers. Joint venture receivables are typically collected in one to three months of the joint venture bill being issued to the partner. The Company attempts to mitigate the risk from joint venture receivables by obtaining partner approval of significant capital expenditures prior to the expenditure. However, the receivables are from participants in the petroleum and natural gas sector, and collection of the outstanding balances is dependent on industry factors such as commodity price fluctuations, escalating costs and the risk of unsuccessful drilling. In addition, a further risk exists with joint venture partners, such as disagreements, that increase the potential for non-collection. The Company does not typically obtain collateral from petroleum and natural gas marketers or joint venture partners; however, the Company does have the ability to withhold information and production from joint venture partners in the event of non-payment.

As at November 30, 2010 the Company's accounts receivable was $107,026 (August 31, 2010 $53,060) of which $27,089 is due from government agencies (August 31, 2010 $23,935), $5,698 is due from a gas marketer (August 31, 2010 $5,797) $44,275 is due from a joint venture partner (August 31, 2010 $15,391) and the balance of $29,964 is due from other trade receivables (August 31, 2010 $7,937).

The carrying amount of cash and cash equivalents and accounts receivable represents the Company's maximum credit exposure.

As at November 30, 2010 and August 31, 2010 the Company's accounts receivable is aged as follows:

	November 30, 2010	August 31, 2010
Current (less than 90 days)	$61,832	$36,789
Past due (more than 90 days)	45,194	16,271
Total	**$107,026**	$53,060

Liquidity Risk
Liquidity risk includes the risk that, as a result of the Company's operational liquidity requirements:

- The Company will not have sufficient funds to settle their obligations or other transactions on the date they come due;
- The Company will be forced to sell financial assets at a value which is less than what they are worth; or
- The Company may be unable to settle or recover a financial asset at all.

The Company's operating cash requirements including amounts projected to complete the Company's existing capital expenditure program are continuously monitored and adjusted as input variables change. These variables include but are not limited to, shareholder loans, oil and natural gas production from existing wells, results from new wells drilled, commodity prices, cost overruns on capital projects and regulations relating to prices, taxes, royalties, land tenure, allowable production and availability of markets. These variables create liquidity risk which has necessitated the need to raise financing to meet capital and operating cash-flow needs. The Company has liquidity risk which necessitates the Company to obtain debt financing, enter into joint venture arrangements, or raise equity. There is no assurance the Company will be able to obtain the necessary financing in a timely manner.

The following table illustrates the contractual maturities of financial liabilities:

November 30, 2010	**Payments Due by Period**				
	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Accounts payable	$853,725	$853,725	-	-	-
Loan payable	110,000	110,000	-	-	-
Secured notes payable (1)	1,164,964	179,620	$985,344	-	-
Shareholders loans (1)	1,694,780	1,694,780	-	-	-
Asset retirement obligation	18,025	-	-	-	$18,025
Total contractual obligations	**$3,841,494**	**$2,838,125**	**$985,344**	**-**	**$18,025**

August 31, 2010	Payments Due by Period				
	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Accounts payable	$488,741	$488,741	-	-	-
Loan payable	110,000	110,000	-	-	-
Secured notes payable (1)	1,207,527	186,183	$1,021,344	-	-
Due to shareholder	57,500	57,500	-	-	-
Asset retirement obligation	3,907	-	-	-	$3,907
Total contractual obligations	$1,867,675	$842,424	$1,021,344	-	$3,907

(1) Translated at current exchange rate.

Market Risk
Market risk represents the risk of loss that may impact our financial position, results of operations, or cash flows due to adverse changes in financial market prices, including interest rate risk, foreign currency exchange rate risk, commodity price risk, and other relevant market or price risks. We do not have activities related to derivative financial instruments or derivative commodity instruments. We hold equity securities which have been written down to $1 on our consolidated balance sheet.

The oil and gas industry is exposed to a variety of risks including the uncertainty of finding and recovering new economic reserves, the performance of hydrocarbon reservoirs, securing markets for production, commodity prices, interest rate fluctuations, potential damage to or malfunction of equipment and changes to income tax, royalty, environmental or other governmental regulations.

We mitigate these risks to the extent we are able by:

- utilizing competent, professional consultants as support teams to company staff.
- performing careful and thorough geophysical, geological and engineering analyses of each prospect.
- focusing on a limited number of core properties.

Market risk is the possibility that a change in the prices for natural gas, natural gas liquids, condensate and oil, foreign currency exchange rates, or interest rates will cause the value of a financial instrument to decrease or become more costly to settle.

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and continued in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and may impact the performance of the global economy going forward. Although economic conditions improved towards the latter portion of 2009, as anticipated, the recovery from the recession has been slow in various jurisdictions including in Europe and the United States and has been impacted by various ongoing factors including sovereign debt levels and high levels of unemployment which continue to impact commodity prices and to result in high volatility in the stock market.

(i) Commodity Price Risk

Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for petroleum and natural gas are impacted by world economic events that dictate the levels of supply and demand.

The Company believes that movement in commodity prices that are reasonably possible over the next twelve month period will not have a significant impact on the Company.
Commodity Price Sensitivity:

The following table summarizes the sensitivity of the fair value of the Company's risk management position for the period ended November 30, 2010 and 2009 to fluctuations in natural gas prices, with all other variables held constant. When assessing the potential impact of these price changes, the Company believes that 10 percent volatility is a reasonable measure. Fluctuations in natural gas prices potentially could have resulted in unrealized gains (losses) impacting net income as follows:

	November 30, 2010		November 30, 2009	
	Increase 10%	**Decrease 10%**	Increase 10%	Decrease 10%
Revenue	**$ 18,809**	**$ 15,389**	$ 28,884	$ 23,632
Net loss	**$ (97,282)**	**$ (100,702)**	$ (77,673)	$ (82,925)

(ii) Foreign Exchange Risk

The Company is exposed to the financial risk related to the fluctuation of foreign exchange rates The prices received by the Company for the production of natural gas and natural gas liquids are primarily determined in reference to U.S. dollars but are settled with the Company in Canadian dollars. The Company's cash flow for commodity sales will therefore be impacted by fluctuations in foreign exchange rates. The Company considers this risk to be limited.

The Company operates in Canada and the United States and a portion of its expenses are incurred in United States dollars. A significant change in the currency exchange rates between the CDN dollar relative to US dollar could have an effect on the Company's results of operations, financial position or cash flows. The Company believes that a change in the exchange rate could be reasonably possible within the next reporting period. A 5% change would give rise to a change in net loss and comprehensive loss at November 30, 2010 of approximately $4,950.

The Company is exposed to currency risk through the following assets and liabilities denominated in US$ at November 30, 2010 and August 31, 2010.

	November 30, 2010	August 31, 2010
Financial Instrument	**US$**	US$
Cash and cash equivalents	$184,517	$5,046
Accounts receivable	59,096	21,926
Due from related party	-	1,245
Accounts payable	480,393	198,015
Shareholder loans	1,450,000	-
Secured notes payable	1,135,000	1,135,000
Total US$	3,309,006	$1,361,232
CDN dollar equivalent at period end	$3,396,364	$1,448,215

(iii) Interest Rate Risk

Interest rate risk refers to the risk that the value of a financial instrument or cash flows associated with the instrument will fluctuate due to changes in market interest rates. The majority of the Company's debt is in fixed rate secured notes payable. As at November 30, 2010 the Company did not have any interest rate hedges.

Based on management's knowledge and experience of the financial markets, the Company believes that the movements in interest rates that are reasonably possible over the next twelve month period will not have a significant impact on the Company.

CAPITAL MANAGEMENT

The Company's objectives when managing capital is to safeguard the entity's ability to continue as a going concern. The Company sets the amount of capital in proportion to risk. The Company manages the capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of any underlying assets. In order to maintain or adjust capital structure the Company may from time to time issue equity, issue debt, adjust its capital spending and sell assets to manage current and projected debt levels. The board of directors does not establish quantitative return on capital criteria for management, but rather relies on the expertise of the Company's management to sustain future development of the business.

As at November 30, 2010 and August 31, 2010 the Company considers its capital structure to include the following:

	November 30, 2010	August 31, 2010
Shareholders' equity	$4,183,700	$4,239,777
Long term debt	(1,003,370)	(1,025,251)
Working capital deficiency	(2,458,064)	(744,262)
	$722,266	$2,470,264

Management reviews its capital management approach on an ongoing basis and believes that this approach, given the relative size of the Company, is reasonable.

There were no changes in the Company's capital management during the period ended November 30, 2010.

The Company is not subjected to any externally imposed capital requirements.

RESULTS OF OPERATIONS

Historical Production	For the Three Months Ended November 30, 2010	November 30, 2009
Natural gas – mcf/d	53	78
Historical Prices		
Natural gas - $/mcf	$ 3.53	$ 3.71
Royalties costs - $/mcf	$ 0.64	$ 0.69
Production costs - $/mcf	$ 3.42	$ 3.53
Net back - $/mcf	$ (0.53)	$ (0.51)
Operations		
Revenue	$ 17,099	$ 26,258
Net loss and comprehensive loss for the period	$98,992	$ 80,299
Net loss per share	$0.003	$ 0.004

Production Volume
For the three months ended November 30, 2010 average natural gas sales volumes increased to 53 mcf/d compared to 78 mcf/d for the comparable period in 2009. The decrease in average sales volumes was primarily attributed to natural production declines from the Company's Botha, Alberta property. Production volume for the three months ended November 30, 2010 was 4,838 mcf compared to 7,077 mcf for the comparable period in 2009.

Commodity Prices
For the three months ended November 30, 2010 average natural gas prices received per mcf decreased 5% to $3.53 compared to $3.71 per mcf for the same period ending November 30, 2009. The decreased in average natural gas prices received was attributed to lower commodity prices for natural gas during the period.

Revenue
For the three months ended November 30, 2010 revenue decreased by $9,159 to $17,099 compared to $26,258 for the same period in 2009. The decrease in revenue for the three months ended November 30, 2010 was primarily attributed to lower production volume as a result of natural production declines and lower commodity prices received.

Operating Costs
For the three months ended November 30, 2010 operating costs were $19,817 compared to operating costs of $29,947 for the three months ended November 30, 2009. In the decrease in operating costs for the three months ended November 30, 2010 was primarily attributed to the decreased production volume.

Depletion
Depletion for the three months ended November 30, 2010 decreased by $4,024 to $5,742 compared to $9,766 for the same period in 2009. The decrease in depletion for the three months ended November 30, 2010 was attributed to lower production volume from the Company's Botha, Alberta property

Administrative Expenses
Administrative expenses for the three months ended November 30, 2010 were $90,532 compared to $66,874 for the three months ended November 30, 2009. The increase in expenses during 2010 was primarily attributed to: interest expense of $37,967 compared to Nil in 2009; an increase in head office expenses of $22,957 to $25,957 compared to $3,000 in 2009; an increase in consulting fees of $19,245 compared to Nil in 2009; an increase in transfer agent and registrar costs of $16,114 to $18,037 compared to $1,923 in 2009; an increase in general and office costs of $3,329 to $3,846 compared to $517 in 2009; and an increase in professional fees of $3,175 to $57,109 compared to $53,934 for the same three month period in 2009. These increases in administrative expenses for the three months ended November 30, 2010 were partially offset by a foreign exchange gain of $36,110 compared to nil and an expense recovery of $35,519 compared to nil for the three months ended November 30, 2009. Higher administrative expenses for the three month period November 30, 2010 were partially attributed to increased operations from the acquisition of Dyami Energy.

Interest
For the three months ended November 30, 2010 interest income was $Nil compared to $30 for the comparable period in 2009.

Net loss and comprehensive loss for the period
Net loss and comprehensive loss for three months ended November 30, 2010 was $98,992 compared to a net loss of $80,299 for the prior three month period in 2009. The increase in net loss and comprehensive loss for the three months ended November 30, 2010 was primarily related to a decrease in revenue and increases in administrative expenses.

Net loss per share
The net loss per share for the three months ended November 30, 2010 was $0.003 compared to a net loss per share of $0.004 for the same three month period in 2009.

SUMMARY OF QUARTERLY RESULTS

The following tables reflect the summary of quarterly results for the periods set out.

	2010	**2010**	**2010**	**2010**
For the quarter ending	**November 30**	**August 31**	**May 31**	**February 28**
Revenue	$ 17,099	$ 23,363	$ 19,291	$ 36,461
Net loss and comprehensive loss for the period	$ (98,992)	$ (496,520)	$ (75,144)	$ (36,746)
Loss per share	$ (0.003)	$ (0.020)	$ (0.003)	$ (0.002)

Revenue for the four quarters in 2010 fluctuated as a result of changes in production volume and commodity prices received. The increase in net loss and comprehensive loss for the quarter ending August 31, 2010 was primarily attributed to the Company recording a consulting fee of $326,511 upon the issuance of warrants and higher administrative expenses due increased operations from the acquisition of Dyami Energy. During the fourth quarter the Company incurred an increase in professional fees for year-end audit costs and costs associated with the evaluation of the Company’s reserves.

	2009	**2009**	**2009**	**2009**
For the quarter ending	**November 30**	**August 31**	**May 31**	**February 28**
Revenue	$ 26,259	$ 23,078	$ 32,796	$ 260
Net loss and comprehensive loss for the period	$ (80,299)	$ (249,967)	$ (62,554)	$ (9,721)
Loss per share	$ (0.014)	$ (0.014)	$ (0.005)	$ (0.001)

Revenue for the quarters ended November, August and May 2009 increased as a result of the acquisition of 1354166 Alberta. The increase in net loss and comprehensive loss for the quarter ending August 31, 2009 was primarily attributed to a write down of oil and gas interests, an increase in professional fees including year-end audit costs, transfer and registrar costs, office and general expenses, management fees and head office services, and costs associated with the evaluation of the Company’s reserves.

CAPITAL EXPENDITURES

For the three months ended November 30, 2010, the Company incurred costs of approximately $1,627,606 on drilling and initial completion costs for its Mathews/Dyami #1H well in Zavala County, Texas.

The Company expects that its capital expenditures will increase in future reporting periods as the Company incurs capital expenditures to exploration and develop its oil and gas properties.

FINANCING ACTIVITIES

During the three month period ended November 30, 2010, 500,000 common share purchase warrants were exercised at $0.07 expiring February 5, 2014 for proceeds of $35,000. And 600,000 common share purchase warrants were exercised at $0.07 expiring February 27, 2014 for proceeds of $42,000.

During the three month period ended November 30, 2010 the Company received US$1,450,000 and CDN$149,000 and issued demand promissory notes bearing interest at 10% per annum. Interest is payable annually on the anniversary date of the notes.

On November 5, 2010, the Company terminated the agreement dated June 10, 2010 with Gar Wood Securities, LLC ("Gar Wood") to act as Investment Banker/Financial Advisor to the Company for a period of two years. As a result 36,430 warrants were cancelled out of the 333,333 warrants issued, exercisable at $1.00 expiring December 10, 2011 and 18,215 warrants were cancelled out of the 166,667 warrants issued exercisable at $1.50 expiring June 10, 2012.

LIQUIDITY AND CAPITAL RESOURCES

Cash as of November 30, 2010 was $273,034 compared to cash of $43,776 at August 31, 2010. During the three months ended November 30, 2010 the Company received proceeds from the exercise of warrants in the amount of $77,000 and received US$1,450,000 and CDN$149,000 and issued demand promissory notes to four shareholders bearing interest at 10% per annum. Interest is payable annually on the anniversary date of the notes.

For the three months ended November 30, 2010 the primary use of funds was related to drilling the Company's Mathews #1H well. The Company incurred $1,627,606 in costs related to drilling and initial completion on its Dyami/Matthews #1H well located in Zavala County, Texas. The Company's working capital deficiency at November 30, 2010 is $2,458,064 compared to a working capital deficiency of $744,262 at August 31, 2010.

Our current assets of $380,061 as at November 30, 2010 ($98,162 as of August 31, 2010) include the following items: cash $273,034 ($43,776 as of August 31, 2010); marketable securities $1 ($1 as of August 31, 2010); accounts receivable- $107,026 ($53,060 as of August 31, 20010) and due from related party $Nil ($1,325 as of August 31, 2010).

Our current liabilities of $2,838,125 as of November 30, 2010 ($842,424 as of August 31, 2010) include the following items: accounts payable $853,725 ($488,741 as of August 31, 2010); due to shareholders $1,694,780 ($57,500 as of August 31, 2010); loan payable $110,000 ($110,000 as of August 31, 2010); and secured note payable of $179,620 ($183,186 as of August 31, 2010).

At November 30, 2010 the Company has outstanding the following common share purchase warrants: 2,575,000 warrants exercisable at $0.20 per share; 10,560,820 warrants exercisable at $0.07 per share; 296,903 warrants exercisable at US$1.00 per share; 148,452 warrants exercisable at US$1.50 per share; and 1,709,233 warrants exercisable at US$1.00 per share. If any of these common share purchase warrants are exercised it would generate additional capital for us.

Management of the Company recognizes that cash flow from operations is not sufficient to expand its oil and gas operations and reserves or meet its working capital requirements. The Company has liquidity risk which necessitates the Company to obtain debt financing, enter into joint venture arrangements, or raise equity. There is no assurance the Company will be able to obtain the necessary financing in a timely manner.

The Company's past primary source of liquidity and capital resources has been loans and advances, cash flow from oil and gas operations, proceeds from the sale of marketable securities and the issuance of common shares.

If the Company issued additional common shares from treasury it would cause the current shareholders of the Company dilution.

OFF-BALANCE SHEET ARRANGEMENTS

The Company has no off-balance sheet arrangements.

SEGMENTED INFORMATION

The Company's only segment is oil and gas exploration and production and includes two geographic areas, Canada and the United States. The accounting policies applied to Eagleford's operating segments are the same as those described in the summary of significant accounting policies.

Geographic information:

The following is segmented information the period ended November 30, 2010 and 2009:

	November 30, 2010		November 30, 2009	
	Interest and other income	Net income (loss)	Interest and other income	Net income (loss)
Canada	$ -	$ (59,442)	$ 30	$ (80,299)
United States	-	(39,550)	-	-
Total	**$ -**	**$ (98,992)**	$ 30	$ (80,299)

The following is segmented information as at November 30, 2010 and August 31, 2010:

	As at November 30, 2010		As at August 31, 2010	
	Oil and gas interests	Other assets	Oil and gas interests	Other assets
Canada	$ 308,258	$ 116,423	$ 314,000	$ 68,141
United States	7,336,875	263,638	5,695,290	30,021
Total	**$ 7,645,133**	**$ 380,061**	$ 6,009,290	$ 98,162

SEASONALITY AND TREND INFORMATION

The Company's oil and gas operations is not a seasonal business, but increased consumer demand or changes in supply in certain months of the year can influence the price of produced hydrocarbons, depending on the circumstances. Production from the Company's oil and gas properties is the primary determinant for the volume of sales during the year.

The level of activity in the oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas properties are located in areas that are inaccessible except during the winter months because of swampy terrain and other areas are inaccessible during certain months of year due to deer hunting season. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Company.

The impact on the oil and gas industry from commodity price volatility is significant. During periods of high prices, producers conduct active exploration programs. Increased commodity prices frequently translate into very busy periods for service suppliers triggering premium costs for their services. Purchasing land and properties similarly increase in price during these periods. During low commodity price periods, acquisition costs drop, as do internally generated funds to spend on exploration and development activities. With decreased demand, the prices charged by the various service suppliers also decline.

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore effected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. Material increases in the value of the Canadian dollar may negatively impact production revenues from Canadian producers. Such increases may also negatively impact the future value of such entities' reserves as determined by independent evaluators. In recent years, the Canadian dollar has increased materially in value against the United States dollar.

The economic impact that the Kyoto Protocol and other environmental initiatives will have on the sector and changes relating to Alberta government royalty programs implemented along with the New Royalty Framework will vary company to company and the amount and degree of these impacts have yet to be determined.

RELATED PARTY TRANSACTIONS AND BALANCES

The following transactions with individuals related to the Company arose in the normal course of business have been accounted for at the exchange amount being the amount agreed to by the related parties, which approximates the arms length equivalent value.

For the three months ended November 30, 2010 the Company paid management fees to the former President, Sandra Hall of $ Nil (November 30, 2009 $7,500).

At November 30, 2010 the Company has a secured note payable to Source Re Work Program, Inc. ("Source") in the amount of US$175,000 (CDN$179,620). Eric Johnson is the President of Source, the Vice President of Operations for Dyami Energy and a shareholder of the Company. At November 30, 2010 accrued interest of CDN$2,239 is included in accounts payable. During the three months ended November 30, 2010 the Company received CDN$1,325 from Source for expenditures relating to the Matthews Lease.

At November 30, 2010 the Company has a secured promissory note in the amount of $ US$960,000 (CDN$985,344) payable to Benchmark Enterprises LLC ("Benchmark`"). Benchmark is a shareholder of the Company. For the period ended November 30, 2010 accrued interest payable to Benchmark of CDN$14,740 was recorded. At November 30, 2010 interest payable to Benchmark in the amount of CDN$40,656 is included in accounts payable.

At November 30, 2010 included in accounts payable is $88,877 due to Gottbetter & Partners LLP for legal fees. Gottbetter Capital Group, Inc. is a shareholder of the Company. Adam Gottbetter is sole owner of Gottbetter & Partners LLP and Gottbetter Capital Group, Inc.

The loan payable in the amount of $57,500 is due to a shareholder and is unsecured, non-interest bearing and repayable on demand. At November 30, 2010 interest was imputed at a rate of 10% per annum and interest of $1,434 was included in contributed surplus.

During the three month period ended November 30, 2010, the Company received $1,180,360 (US$1,150,000) and $149,000 and issued promissory notes to four shareholders. The notes are due on demand and bear interest at 10% per annum. Interest is payable annually on the anniversary date of the notes. At November 30, 2010 accrued interest of CDN$14,915 is included in accounts payable.

During the three month period ended November 30, 2010, Company received US$300,000 (CDN$307,920) and issued a promissory note to the President of the Company. The note is due on demand and bears interest at 10% per annum. Interest is payable annually on the anniversary date of the note. At November 30, 2010 accrued interest of CDN$4,640 is included in accounts payable. At November 30, 2010 included in accounts payable is $2,804 due to the President for expenditures paid on behalf of the Company.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

The Company has development commitments on its Mathews Lease and Murphy Lease in order to keep the leases in good standing.

Mathews Lease, Zavala County, Texas
Dyami Energy acquired its interest in the Matthews Lease through a Purchase and Sale Agreement dated effective February 23, 2010 (the "Agreement"). Under the terms of the Agreement, Dyami Energy has the following commitments:

(a) On or before August 23, 2010 Dyami Energy shall commence operations to drill an Initial Test Well on Matthews Lease to a depth of not less than 3,000 feet below the surface or to the base of the San Miguel "D" formation;

(b) On or before July 8, 2011, Dyami Energy shall commence operations to perform an injection operation (by use of steam, nitrogen or other) in the San Miguel formation on the Initial Test Well or any other well located on the Matthews Lease or, all of the interest acquired by Dyami Energy in the Matthews Lease shall be forfeited without further consideration;

(c) On or before January 1, 2011, Dyami Energy shall commence a horizontal well to test the Eagle Ford Shale formation with a projected lateral length of not less than 2,500 feet (the "Second Test Well").

Dyami Energy's 15% working interest partner in the Matthews Lease has an obligation to participate in each of the operations provided for in (a), (b) and (c) above and if the partner fails to bear its share of the costs of such operations, the partner shall forfeit its interest in and to the well and the applicable spacing unit.

In August 2010, Dyami Energy commenced operations to drill its Dyami/Matthews #1-H well on the Matthews Lease to a measured depth of 8,563 feet, of which 5,114 feet was vertical depth into the Del Rio formation. The well was whipstocked at the top of the Austin Chalk formation and drilled with an 800 foot curve and extended horizontally 3,300 feet into the Eagle Ford shale formation and accordingly Dyami Energy satisfied (a) and (c) above.

The Dyami/Matthews #1-H well was logged and 36 sidewall cores were taken from 4 key formations, the San Miguel, the Austin Chalk, the Eagle Ford and the Buda. The logs were interpreted by Weatherford International Ltd and the sidewall cores were analyzed by Core Laboratories and Weatherford and based on those results the Company is formulating a detailed frac design and completion plan for the Dyami/Matthews #1 H well.

Dyami Energy is the designated operator under the provisions of the Matthews Lease Operating Agreement.

The Matthews Oil and Gas Lease has a primary term of three years commencing April 12, 2008, unless commercial production is established from a well or lands pooled therewith or the lessee is then engaged in actual drilling or reworking on any well within 90 days thereafter. The lease shall remain in force so long as the drilling or reworking is processed without cessation of more than 90 days. The lease requires that such operations be continuous, without cessation of more than ninety days, and if production is established, then the lease will continue. If the lessee has completed a well as a producer or abandoned a well within forty-five days prior to the expiration of the primary term, the lessee may extend the lease by commencing a well within ninety days following the end of the primary term.

Murphy Lease, Zavala County, Texas

Dyami Energy holds a 100% working interest in a mineral lease comprising approximately 2,637 acres of land in Zavala County, Texas (the "Murphy Lease") subject to a 10% carried interest on the drilling costs from surface to base of the Austin Chalk formation, and a 3% carried interest on the drilling costs from the top of the Eagle Ford shale formation to basement on the first well drilled into a serpentine plug and for the first well drilled into a second serpentine plug, if discovered. Thereafter Dyami Energy's working interests range from 90% to 97%. The royalties payable under the Murphy Lease are 25%.

Dyami Energy acquired its interest in the Murphy Lease through an Assignment Agreement dated effective February 3, 2010 (the "Assignment Agreement"). The Murphy Oil and Gas Mineral Lease ("Mineral Lease Agreement') has a primary term of three years commencing on February 2, 2010. Under the terms of the Assignment Agreement and the Mineral Lease Agreement, Dyami Energy has the following commitments:

a) to commence drilling (spud) a well to a depth to sufficiently test the Eagle Ford Shale formation by August 3, 2010 or pay a lease delay payment of US $25 per acre or US$65,925 in the aggregate (paid July 28, 2010) to extend the period to commence drilling for 180 days to January 30, 2011 or Dyami Energy shall be required to release and re-assign its rights in the Murphy Lease.

b) During the development of the Murphy Lease, Dyami Energy is required to commence drilling a well within 180 days, or otherwise release and re-assign its rights to the Murphy Lease, but excluding the unit acreage area it has already drilled and earned. Likewise, if a producing well ceases to produce, and such well is not timely re-worked or re-drilled within a six month period, Dyami Energy shall also be required to release and re-assign its rights to the Murphy Lease.

c) Three years after the cessation of continuous drilling, all rights below the deepest producing horizon in each unit then being held by production, shall be released and re-assigned to the Lessor, unless the drilling of another well has been proposed on said unit, approved in writing by Lessor, and timely commenced (see Subsequent Events).

Loan Payable
The loan payable in the amount of $110,000 is due to an arms' length party and is unsecured, non-interest bearing and repayable on demand.

Secured Notes Payable

Current
At November 30, 2010, the Company has US$175,000 (CDN$179,620), 5% per annum secured promissory note payable to Source Re-Work Program Inc. (August 31, 2010 CDN$186,183). US$100,000 of principal together with accrued interest is due and payable on February 28, 2011 and US$75,000 of principal together with accrued interest is due and payable on August 31, 2011. At November 30, 2010 accrued interest of CDN$2,239 is included in accounts payable. The note is secured by the Company's 10% working interest in the Matthews Lease, Zavala County, Texas. The Company may, in its sole discretion, prepay any portion of the principal amount.

Long Term
At November 30, 2010 the Company has US$960,000 (CDN$985,344), 6% per annum secured promissory note payable to Benchmark Enterprises LLC (August 31, 2010 CDN$1,201,344). The note is payable on December 31, 2011 or upon the Company closing a financing or series of financings in excess of US$4,500,000. For the period ended November 30, 2010 accrued interest payable to Benchmark of CDN$14,740 was recorded. At November 30, 2010 interest payable to Benchmark in the amount of CDN$40,656 is included in accounts payable. The note is secured by Dyami Energy's 75% working interest in the Matthews Lease and the Company's 100% working interest in the Murphy Lease, Zavala County, Texas. The Company may, in its sole discretion, prepay any portion of the principal amount.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Going Concern
These consolidated financial statements have been prepared on a going concern basis which contemplates the realization of assets and the payment of liabilities in the ordinary course of business. The Company plans to obtain additional financing by way of debt or the issuance of common shares or some other means to service its current working capital requirements, any additional or unforeseen obligations or to implement any future opportunities. Should the Company be unable to continue as a going concern, it may be unable to realize the carrying value of its assets and to meet its liabilities as they become due. These consolidated financial statements do not include any adjustments for this uncertainty.

The Company has accumulated significant losses and negative cash flows from operations in recent years which raises doubt as to the validity of the going concern assumption. As at November 30, 2010, the Company had a working capital deficiency of $2,458,064 and an accumulated deficit of $1,816,227. Management of the Company does not have sufficient funds to meet its liabilities for the ensuing twelve months as they fall due. In assessing whether the going concern assumption is appropriate, management takes into account all available information about the future, which is at least, but not limited to, twelve months from the end of the reporting period. The Company's ability to continue operations and fund its liabilities is dependent on management's ability to secure additional financing and cash flow. Management is pursuing such additional sources of financing and cash flow to fund its operations and while it has been successful in doing so in the past, there can be no assurance it will be able to do so in the future. Management is aware, in making its assessment, of material uncertainties related to events or conditions that may cast significant doubt upon the Company's ability to continue as a going concern. Accordingly, they do not give effect to adjustments that would be necessary should the Company be unable to continue as a going concern and therefore realize its assets and liquidate its liabilities and commitments in other than the normal course of business and at amounts different from those in the accompanying consolidated financial statements.

Principles of Consolidation
On November 12, 2009, the Company's wholly owned subsidiary 1406768 Ontario Inc. changed its name to Eagleford Energy Inc. On November 30, 2009 the Company amalgamated with Eagleford Energy Inc. and upon the

amalgamation the entity's new name became Eagleford Energy Inc. The consolidated financial statements include the accounts of Eagleford, the legal parent, together with its wholly-owned subsidiaries, 1354166 Alberta Ltd. an Alberta operating company and Dyami Energy LLC a Texas limited liability exploration stage company. All inter-company accounts transactions have been eliminated on consolidation.

Oil and Gas Interests
The Company follows the successful efforts method of accounting for its oil and gas interest. Under this method, costs related to the acquisition, exploration, and development of oil and gas interests are capitalized. The Company carries as an asset, exploratory well costs if a) the well found a sufficient quantity of reserves to justify its completion as a producing well and b) the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project. If a property is not productive or commercially viable, its costs are written off to operations. Impairment of non-producing properties is assessed based on management's expectations of the properties.

Depletion and Depreciation
Depletion of petroleum and natural gas properties and depreciation of production equipment are calculated on the unit of production basis based on:

(a) total estimated proved reserves calculated in accordance with National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities;

(b) total capitalized costs, excluding undeveloped lands and unproved costs, plus estimated future development costs of proved undeveloped reserves; and

(c) relative volumes of petroleum and natural gas reserves and production, before royalties, converted at the energy equivalent conversion ratio of six thousand cubic feet of natural gas to one barrel of oil.

Impairment Test
The Company performs an impairment test calculation in accordance with the Canadian Institute of Chartered Accountants' successful efforts method guidelines, including an impairment test on undeveloped properties. The recovery of costs is tested by comparing the carrying amount of the oil and natural gas assets to the reserves report. If the carrying amount exceeds the recoverable amount, then impairment would be recognized on the amount by which the carrying amount of the assets exceeds the present value of expected cash flows using proved plus probable reserves and expected future prices and costs. At November 30, 2010 the Company recorded an impairment of Nil (August 31, 2010 - $54,630).

Revenue Recognition
Revenues associated with the sale of crude oil and natural gas are recorded when the title passes to the customer. The customer has assumed the risks and rewards of ownership, prices are fixed or determinable and collectability is reasonably assured. The Company does not enter into ongoing arrangements whereby it is required to repurchase its products, nor does the Company provide the customer with a right of return.

Royalties
As is normal to the industry, the Company's future production is subject to crown royalties. These amounts are reported net of related tax credits.

Transportation
Costs paid by the Company for the transportation of natural gas, crude oil and natural gas liquids from the wellhead to the point of title transfer are recognized when the transportation is provided.

Environmental and Site Restoration Costs
The Company recognizes an estimate of the liability associated with an asset retirement obligation ("ARO") in the financial statements at the time the liability is incurred. The estimated fair value of the ARO is recorded as a long-term liability with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on a straight-line basis over the estimated life of the asset. The liability amount is increased each reporting period due to the passage of time and the amount of accretion to operations in the period. The ARO can also increase or decrease due to changes in the estimates of timing of cash flows or changes in the original estimated

undiscounted cost. Actual costs incurred upon settlement of the ARO are charged against the ARO to the extent of the liability recorded.

Foreign Currencies
Monetary assets and liabilities denominated in currencies other than Canadian dollars are translated at exchange rates in effect at the balance sheet date. Non-monetary items are translated at historical rates. Revenue and expense items are translated at the average rates of exchange for the year. Exchange gains and losses are included in the determination of net income for the year.

Marketable Securities
At each financial reporting period, the Company estimates the fair value of investments which are held-for-trading, based on quoted closing bid prices at the consolidated balance sheet dates or the closing bid price on the last day the security traded if there were no trades at the consolidated balance sheet dates and such valuations are reflected in the consolidated financial statements. The resulting values for unlisted securities whether of public or private issuers, may not be reflective of the proceeds that could be realized by the Company upon their disposition. The fair value of the securities at November 30, 2010 was $1 (August 31, 2010 - $1)

Financial Instruments
All financial instruments are recorded initially at estimated fair value on the balance sheet and classified into one of five categories: held for trading, held to maturity, available for sale, loans and receivables and other liabilities. Cash and cash equivalents, and marketable securities are classified as held for trading and measured at estimated fair value. Accounts receivable and due from related party are classified as loans and receivables and measured at amortized cost. Accounts payable, loan payable, shareholder loans and secured notes payable are classified as other liabilities and measured at amortized cost.

The Company does not enter into derivative contracts (commodity price, interest rate or foreign currency) in order to manage risk. The Company does not utilize derivative contracts for speculative purposes, has not designated any derivative contracts as hedges, and has not recorded any assets or liabilities as a result of embedded derivatives.

The estimated fair value of cash and cash equivalents, accounts receivable and accounts payable approximate their carrying amounts due to their short terms to maturity.

Cash and cash equivalents
Cash and cash equivalents include bank accounts, trust accounts, and term deposits with maturities of less than three months.

Accounting Estimates
The preparation of the consolidated financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, and the disclosures of revenues and expenses for the reported year. Actual results may differ from those estimates.

The amounts recorded for depletion and amortization of oil and gas properties and the valuation of these properties, are based on estimates of proved and probable reserves, production rates, oil and gas prices, future costs and other relevant assumptions. The effect on the consolidated financial statements of changes in estimates in future periods could be significant.

Income Taxes
The Company accounts for income taxes under the asset and liability method. Under this method, future income tax assets and liabilities are recognized for the future tax consequences attributable to differences between financial reporting and tax bases of assets and liabilities and available loss carry forwards and are measured using the substantively enacted tax rates and laws that will be in effect when the differences are expected to be reversed. A valuation allowance is established to reduce tax assets if it is more likely than not that all or some portions of such tax assets will not be realized.

Non-Monetary Transactions
Transactions in which shares or other non-cash consideration are exchanged for assets or services are measured at the fair value of the assets or services involved in accordance with Section 3831 ("Non-monetary Transactions") of the Canadian Institute of Chartered Accountants Handbook ("CICA Handbook").

Stock-Based Compensation
The Company has a stock-based compensation plan. Any consideration received on the exercise of stock options or sale of stock is credited to share capital. The Company records compensation expense and credits contributed surplus for all stock options granted. Stock options granted during the year are accounted for in accordance with the fair value method of accounting for stock-based compensation. The fair value for these options is estimated at the date of grant using the Black-Scholes option pricing model.

Loss Per Share
Basic loss per share is calculated by dividing the loss for the year by the weighted average number of common shares outstanding during the year. Diluted loss per share is computed using the treasury stock method. Under this method, the diluted weighted average number of shares is calculated assuming the proceeds that arise from the exercise of stock options and other dilutive instruments are used to repurchase the Company's shares at their weighted average market price for the period.

Warrants
When the Company issues units under a private placement comprising common shares and warrants, the Company follows the relative fair value method of accounting for warrants attached to and issued with common shares of the Company. Under this method, the fair value of warrants issued is estimated using a Black-Scholes option price model. The fair value is then related to the total of the net proceeds received on issuance of the common shares and the fair value of the warrants issued therewith. The resultant relative fair value is allocated to warrants from the net proceeds and the balance of the net proceeds is allocated to the common shares issued.

Change in Accounting Policy and Future Accounting Changes
(a) EIC Credit Risk
In January 2009, the CICA's EIC concluded that an entity's own credit risk and the credit risk of the counterparty should be taken into account in determining the fair value of financial assets and financial liabilities, including derivative instruments. The application of incorporating credit risk into the fair value should result in entities re-measuring the financial assets and financial liabilities as at the beginning of the period of adoption. This abstract should be applied retrospectively without restatement of prior periods to all financial assets and liabilities measured at fair value in interim and annual financial statements for periods ending on or after January 20, 2009. Retrospective application with restatement of prior periods is also permitted. The adoption of this standard did not impact the financial position or results of operations of the Company.

(b) Financial Instruments – Disclosures
In June 2009, the Canadian Accounting Standards Board ("AcSB") issued the amendments to CICA Handbook Section 3862, Financial Instruments - Disclosures, which reflect the corresponding amendments made by the International Accounting Standards Board to IFRS 7, Financial Instruments: Disclosures, in March 2009. The amendments require that all financial instruments measured at fair value be presented into one of the three hierarchy levels set forth below for disclosure purposes. Each level is based on the transparency of the inputs used to measure the fair value of assets and liabilities.

(i) Level 1: Inputs are unadjusted quoted prices of identical instruments in active markets.

(ii) Level 2: Valuation models which utilize predominately observable market inputs.

(iii) Level 3: Valuation models which utilize predominately non-observable market inputs.

The classification of a financial instrument in the hierarchy is based upon the lowest level of input that is significant to the measurement of fair value. The amendments to Section 3862 also require additional disclosure relating to the liquidity risk associated with financial instruments. The amendments improve disclosure of financial instruments specifically as it relates to fair value measurements and liquidity risk. The adoption of the amendments did not impact the Company's financial position or results of operations.

(c) Goodwill and Intangible Assets
During fiscal 2010 the Company adopted Section 3064, “Goodwill and Intangible Assets”. This section replaces Section 3062, “Goodwill and Other Intangible Assets” and Section 3450, “Research and Development Costs”. Various changes have made to other sections of the CICA Handbook for consistency purposes. Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition and of intangible assets by profit-oriented enterprises. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062. The adoption of this standard did not have an impact on the Company’s financial statements.

(d) General Standard of Financial Statement Presentation
During fiscal 2010, the Company adopted amended Section 1400, “General Standard of Financial Statement Presentation” which includes requirements to assess and disclose the Company’s ability to continue as a going concern. The adoption of this new section did not have an impact on the Company’s financial statements.

(e) Future Accounting Changes
Business Combinations, Consolidated Financial Statements and Non-controlling Interests – The CICA issued three new accounting standards in January 2009: section 1582, *Business Combinations*, section 1601, *Consolidated Financial Statements*, and section 1602, *Non-controlling interests*. These new standards will be effective for fiscal years beginning on or after January 1, 2011. The Company is in the process of evaluating the requirements of the new standards.

Section 1582 replaces section 1581, and establishes standards for the accounting for a business combination. It provides the Canadian equivalent to International Financial Reporting Standard IFRS 3 – *Business Combinations*. The section applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 1, 2011.

Sections 1601 and 1602 together replace 1600 – *Consolidated Financial Statements.* Section 1601, establishes standards for the preparation of consolidated financial statements. Section 1601 applies to interim and annual consolidated financial statements relating to fiscal years beginning on or after January 1, 2011.

Section 1602 establishes standards for accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. It is equivalent to the corresponding provisions of International Financial Reporting Standard IAS 27 - *Consolidated and Separate Financial Statements* and applies to interim and annual consolidated financial statements relating to fiscal years beginning on or after January 1, 2011.

In December 2009, the CICA issued EIC 175 – “Multiple Deliverable Revenue Arrangements” replacing EIC 142 – “Revenue Arrangements with Multiple Deliverables”. This abstract was amended to: (1) provide updated guidance on whether multiple deliverables exist, how the deliverables in an arrangement should be separated, and the consideration allocated; (2) require, in situations where a vendor does not have vendor-specific objective evidence (“VSOE”) or third-party evidence of selling price, that the entity allocate revenue in an arrangement using estimated selling prices of deliverables; (3) eliminate the use of the residual method and require an entity to allocate revenue using the relative selling price method; and (4) require expanded qualitative and quantitative disclosures regarding significant judgments made in applying this guidance. The accounting changes summarized in EIC 175 are effective for fiscal periods beginning on or after January 1, 2011, with early adoption permitted. Adoption may either be on a prospective basis or by retrospective application. If the Abstract is adopted early, in a reporting period that is not the first reporting period in the entity’s fiscal period, it must be applied retrospectively from the beginning of the Company’s fiscal period of adoption. The Company expects to adopt EIC 175 effective January 1, 2011. The Company does not believe the standard will have a material impact on its consolidated financial statements.

In February 2008, the Accounting Standards Board “(AcSB)” confirmed that the use of IFRS will be required in 2011 for publicly accountable enterprises in Canada. In April 2008, the AcSB issued an IFRS Omnibus Exposure Draft proposing that publicly accountable enterprises be required to apply IFRS, in full and without modification, for fiscal years beginning on or after January 1, 2011. The Company will issue its initial unaudited consolidated financial statements under IFRS including comparative information for the period ending November 30, 2011.

The eventual changeover to IFRS represents changes due to new accounting standards. The transition from current Canadian GAAP to IFRS is a significant undertaking that may materially affect the Company's reported financial position and results of operations.

The Company is assessing the potential impacts of this changeover and is developing its IFRS changeover plan, which will include project structure and governance, resourcing and training, analysis of key GAAP differences and a phased plan to assess accounting policies under IFRS as well as potential exemptions to the initial adoption of IFRS as permitted by IFRS Statement 1.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

In February 2008, the Accounting Standards Board "(AcSB)" confirmed that the use of IFRS will be required in 2011 for publicly accountable enterprises in Canada. In April 2008, the AcSB issued an IFRS Omnibus Exposure Draft proposing that publicly accountable enterprises be required to apply IFRS, in full and without modification, for fiscal years beginning on or after January 1, 2011. The Company will issue its initial unaudited consolidated financial statements under IFRS including comparative information for the period ending November 30, 2011.

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The Company is assessing the potential impacts of this changeover and is developing its IFRS changeover plan, which will include project structure and governance, resourcing and training, analysis of key GAAP differences and a phased plan to assess accounting policies under IFRS as well as potential exemptions to the initial adoption of IFRS as permitted by IFRS Statement 1.

Transition to International Financial Reporting Standards

The transition from current Canadian GAAP to IFRS is a significant undertaking that may materially affect the Company's reported financial position and results of operations. The Company is assessing the potential impacts of this changeover and has commenced the development of an IFRS implementation plan to prepare for this transition, which will include project structure and governance, resourcing and training, analysis of key GAAP differences and a phased plan to assess accounting policies under IFRS as well as potential exemptions to the initial adoption of IFRS as permitted by IFRS Statement 1.

The table below summarizes the key elements of the transition plan and the expected timing of activities related to the Company's transition:

Initial analysis of key areas for which changes to accounting policies may be required	Completed
Detailed analysis of all relevant IFRS requirements and identification of area requiring accounting policy changes or those with accounting policy alternatives	Throughout fiscal 2011
Assessment of first-time adoption (IFRS 1) requirements and alternatives	Throughout fiscal 2011
Final determination of changes to accounting policies and choices to be made with respect to first-time adoption alternatives	Q2, Q3 (August 31, 2011)
Resolution of the accounting policy change implications on information technology, internal controls and contractual arrangements	Q2, Q3 (August 31, 2011)
Management and employee training	Throughout the transition period
Quantification of the Financial Statement impact of changes in accounting policies	Throughout fiscal 2011

The Company is in the process of analyzing key areas where changes to current accounting policies may be required. While an analysis will be required for all accounting policies, the initial key areas of assessment include:

• Property, Plant and Equipment
  - Pre-exploration costs
  - Exploration and evaluation costs
  - Depletion, depreciation and amortization
• Impairment testing
• Decommissioning liabilities (known as "asset retirement obligations" under Canadian GAAP)
• Stock-based compensation
• Income taxes

Each of these significant impact areas is discussed in more detail below.

Property, Plant and Equipment
IFRS and Canadian GAAP contain the same basic principles for property, plant, and equipment; however, there are some differences. Specifically, IFRS requires property, plant and equipment to be measured at cost in accordance with IFRS, breaking down material items into components and amortizing each one separately. In addition, unlike Canadian GAAP, IFRS permits property, plant and equipment to be measured at fair value or amortized cost. The Company's initial analysis is that no further componentization was necessary in property, plant, and equipment.

In moving to IFRS, the Company will be required to adopt different accounting policies for pre-exploration activities, exploration and evaluation costs and depletion, depreciation and accretion.

Pre-exploration costs are costs incurred before the Company obtains the legal right to explore an area. Under Canadian GAAP, these costs are capitalized, while under IFRS, these costs must be expensed. At this time, the Company does not anticipate that this accounting policy difference will have a significant impact on the financial statements.

During the Exploration and Evaluation phase, the Company capitalizes costs incurred for these projects under Canadian GAAP. Under IFRS, the Corporation has the alternative to either continue capitalizing these costs until technical feasibility and commercial viability of the project is determined, or to expense these costs as incurred. The Company does not currently have any Exploration and Evaluation assets.

Under Canadian GAAP, the Company calculates its depletion, depreciation and amortization rate at the country cost centre level. Under IFRS, this rate will be calculated at a lower unit of account level. At this time, the Company has not finalized its policy in this regard, and therefore the impact of this difference in accounting policy is not reasonably determinable.

Impairment Testing
For the first step of the impairment test under Canadian GAAP, future cash flows are not discounted. Under IFRS, the future cash flows are discounted. In addition, for Property, Plant and Equipment, impairment testing is currently performed at the country cost centre level, while under IFRS, it will be performed at a lower level, referred to as a cash-generating unit. The impairment calculations will be performed using either total proved or proved plus probable reserves. Canadian GAAP prohibits reversal of impairment losses. Under IFRS if the conditions giving rise to impairment have reversed, impairment losses previously recorded would be partially or fully reversed to eliminate write-downs recorded. The Company expects to adopt these changes in accounting policy prospectively. At this time, the impact of accounting policy differences related to impairment testing is not reasonably determinable.

Asset Retirement Obligation
Under Canadian GAAP, the Company recognizes a liability for the estimated fair value of the future retirement obligations associated with Property, Plant and Equipment. The fair value is capitalized and amortized over the same period as the underlying asset. The Company estimates the liability based on the estimated costs to abandon and reclaim its net ownership interest in wells and facilities, including an estimate for the timing of the costs to be incurred in future periods. These cash outflows are discounted using a credit-adjusted rate. Changes in the net present value of the future retirement obligation are expensed through accretion as part of depletion, depreciation and accretion. Under IFRS, these liabilities are known as "decommissioning liabilities" and are included in the scope of IAS 37 *Provisions, Contingent Liabilities and Contingent* Assets. Decommissioning liabilities are calculated at each reporting period by estimating the risk-adjusted future cash outflows which are discounted using a risk-free rate. Changes in the net present value of the future retirement obligation are expensed through accretion as

part of depletion, depreciation and accretion. Due to the change in the discount rate from a credit-adjusted rate to a risk-free rate, the Company expects there will be an increase in the value of the decommissioning liability under IFRS as compared to Canadian GAAP.

Stock-based Compensation
IFRS 2 *Share-Based Payments* requires the expense related to share-based payments to be recognized as the options vest; that is, for options that vest over a period of time, each tranche must be treated as a separate option grant which accelerates the expense recognition in comparison to Canadian GAAP which allows the expense to be recognized on a straight-line basis over the period the options vest. While the carrying value for each reporting period will be different under IFRS, the cumulative expense recognized over the life of the instrument under both methods will be the same. Going forward under IFRS, stock-based compensation is expected to be higher because the graded vesting requirements of IFRS result in accelerated expense recognition.

Accounting for Income Tax
In transitioning to IFRS, the carrying amount of the Company's tax balances will be directly impacted by the tax effects resulting from changes required by the above IFRS accounting policy differences. Due to the recent withdrawal of the exposure draft on IAS 12 *Income Taxes* in November 2009, the Company is still determining the impact of the revised standard on its IFRS transition. Therefore, at this time the income tax impacts of the differences are not reasonably determinable.

As the analysis of each of the key areas progress, other elements of the Company's IFRS transition plan will also be addressed, including the implication of changes to accounting policies and processes, financial statement note disclosures on information technology, internal controls, contractual arrangements and employee training.

Changes to IFRS Accounting Standards
The Company's analysis of accounting policy differences specifically considers the current IFRS standards that are in effect. The Corporation will continue to monitor any new or amended accounting standards that are issued by the IASB.

Internal Controls over Financial Reporting
The Company does not anticipate that the transition to IFRS will have a significant impact on either its internal controls over financial reporting, or its disclosure controls and procedures. As the review of the Company's accounting policies is completed, an assessment will be made to determine changes necessary for internal controls over financial reporting. This will be an ongoing process throughout fiscal 2010 and 2011 to ensure that all changes in accounting policies include the appropriate additional controls and procedures for future IFRS reporting requirements.

Education and Training
The Company will involve its management and board of directors in the IFRS transition throughout fiscal 2010 and 2011.

Impacts to our Business
The Company does not expect that the adoption of IFRS in 2011 will have a significant impact or influence on its business activities.

OTHER MD&A REQUIREMENTS

(a) Additional Information

Additional information relating to the Company may be obtained or viewed from the System for Electronic Data Analysis and Retrieval (SEDAR) at www.sedar.com and via the Electronic Data Gathering Analysis and Retrieval System (EDGAR) at www.sec.gov.

(b) Share Capital and Contributed Surplus as at November 30, 2010 and the date of this MD&A

Authorized:
Unlimited number of common shares
Unlimited non-participating, non-dividend paying, voting redeemable preference shares

Issued:

Common Shares	Number	Amount
Balance August 31, 2010	29,751,026	$ 3,817,184
Exercise of warrants (note a)	1,100,000	103,400
Balance November 30, 2010	**30,851,026**	**$ 3,920,584**

(a) During the three month period ended November 30, 2010, 500,000 common share purchase warrants were exercised at $0.07 expiring February 5, 2014 for proceeds of $35,000 and 600,000 common share purchase warrants were exercised at $0.07 expiring February 27, 2014 for proceeds of $42,000. The amount allocated to warrants based on relative fair value using Black Scholes model was $26,400.

The following table summarizes the changes in warrants for the three month period ended November 30, 2010:

	2010	
Warrants	**Number of Warrants**	**Weighted Average Price**
Outstanding August 31, 2010	16,445,053	$ 0.22
Exercised (note a)	(1,100,000)	0.07
Cancelled (note b)	(36,430)	US $1.00
Cancelled (note b)	(18,215)	US $1.50
Outstanding November 30, 2010	**15,290,408**	**$0.23**

(b) On November 5, 2010, the Company terminated the agreement dated June 10, 2010 with Gar Wood Securities, LLC ("Gar Wood") to act as Investment Banker/Financial Advisor to the Company for a period of two years. As a result 36,430 warrants were cancelled out of the 333,333 warrants issued, exercisable at $1.00 expiring December 10, 2011 and 18,215 warrants were cancelled out of the 166,667 warrants issued exercisable at $1.50 expiring June 10, 2012. The amount allocated to warrants based on relative fair value using Black Scholes model was $23,315 and $12,204 respectively.

The following table summarizes the outstanding warrants as at November 30, 2010:

Number of Warrants	Exercise Price	Expiry Date	Warrant Value ($)
2,575,000	$0.20	April 14, 2011	$ 100,875
1,000,256	$0.07	February 25, 2014	24,006
9,560,564	$0.07	February 27, 2014	229,453
296,903	US$1.00	December 10, 2011	191,057
148,452	US $1.50	June 10, 2012	99,935
1,709,233	US$1.00	August 31, 2014	1,388,833
15,290,408			**$ 2,034,159**

The fair value of the warrants was estimated on the date of issue using the Black-Scholes pricing model.

Weighted Average Shares Outstanding	November 30, 2010	November 30, 2009
Weighted average shares outstanding, basic	**30,657,619**	21,026,618
Dilutive effect of warrants	**15,531,855**	13,146,371
Weighted average shares outstanding, diluted	**46,189,474**	34,172,989

The effects of any potential dilutive instruments on loss per share related to the outstanding warrants are anti-dilutive and therefore have been excluded from the calculation of diluted loss per share.

Stock Option Plan

The Company has a stock option plan to provide incentives for directors, officers and consultants of the Company. The maximum number of shares, which may be set aside for issuance under the stock option plan, is 4,846,512 common shares. To date, no options have been issued.

Contributed Surplus

Contributed surplus transactions for the respective periods are as follows:

		Amount
Balance, August 31, 2010	$	43,750
Imputed interest (see Related Party Transactions)		1,434
Balance, November 30, 2010	**$**	**45,184**

(c) Disclosure Controls and Procedures

In connection with National Instrument 52-109 (Certificate of Disclosure in Issuer's Annual and Interim Filings) ("NI 52-109") the Chief Executive Officer and Chief Financial Officer of the Company have filed a Venture Issuer Basic Certificate with respect to the financial information contained in the Unaudited Consolidated Financial Statements for the period endedNovember30, 2010 and this accompanying MD&A. In contrast to the full certificate under NI 52-109, the Venture Issuer Basic Certificate does not include representations relating to the establishment and maintenance of disclosure controls and procedures and internal control over financial reporting, as defined in NI 52-109. For further information the reader should refer to the Venture Issuer Basic Certificates filed by the Company with the Annual Filings on SEDAR at www.sedar.com.

SUBSEQUENT EVENTS

On January 20, 2011 the Company spud its 100% working interest Murphy/Dyami #1H test well on its 2,637 gross acre Murphy Lease located in Zavala County, Texas.

Subsequent to the three month period ended November 30, 2010, the Company received US$610,000 and issued promissory notes to four shareholders. The notes are payable on demand and bear interest at 10% per annum. Interest is payable annually on the anniversary date of the notes.