This Management's Discussion and Analysis ("MD&A") of the consolidated financial position and results of operations of the Company, which includes its subsidiaries and partnership arrangements, was prepared as of December 21, 2010, and is for the three and nine months ended October 31, 2010 and 2009. For a full understanding of the consolidated financial position and results of operations of the Company, the MD&A should be read in conjunction with the documents filed on SEDAR, including historical financial statements and press releases. These documents are available at www.sedar.com. The selected financial information contained herein has been prepared in accordance with Canadian Generally Accepted Accounting principles, and are expressed in Canadian dollars, unless otherwise noted.

The Company's Board of Directors and Audit Committee have reviewed and approved the interim consolidated financial statements and MD&A.

Readers are cautioned of the advisories of forward-looking statements, estimates, non-GAAP measures and numerical references which can be found at the end of this MD&A. This MD&A is dated and was prepared using currently available information as of December 21, 2010.

Description of the Company

Thunderbird Energy Corp. (the "Company") is a Canadian based natural resource company focused on the exploration, exploitation, acquisition and production of natural gas and crude oil, primarily in the United States. The Company owns and operates a producing natural gas field in Carbon County, Utah, known as the Gordon Creek field, and holds a 50% interest in a producing light oil project located in Rush County, Kansas. The Company also holds a 100% in an exploration project in Weston County, Wyoming.

HIGHLIGHTS AND OUTLOOK

Highlights of the Company's activities during the quarter were as follows:

- The Company has expanded its Gordon Creek land base by 85% over the past few months, to roughly 7600 acres. The Company intends to continue to acquire contiguous acreage, all of which is considered prospective for development and some of which is expected to add reserves. The impact of these land acquisitions on the Company's net reserve position will be assessed as of the Company's January 31, 2011 year end.

- Building on the Gordon Creek Best Practices Study completed by the Company in 2009, the Company has mapped out an extensive 3 stage development plan, the first 2 stages of which contemplate drilling of up to 36 wells and re-completing a further 5 standing wells. Activities to date include extensive geological and engineering analysis, the development of specific drilling and completion protocols, detailed cost estimation and economic analyses. Roads, pipeline routes and an initial 26 drilling locations have been formally surveyed and the permitting process has been initiated. The development plan has been designed in consultation with various stakeholders including local and State wildlife officials. The development plan has also been completed in consultation with Artola Energy, LLC of Houston Texas, in accordance with the previously announced joint venture agreement. Artola has not been able to complete the required initial joint venture financing of $20 million to date, however the Company is continuing to work with Artola on a non-exclusive basis. The Company is also seeking alternative arrangements to finance the Gordon Creek development plan.

- The Company substantially strengthened its balance sheet by closing approximately $7.34 million of a planned $7.5 million three year natural gas linked debenture financing. The Company also raised an additional $725,000 by way of a unit private placement at a price of $0.15 per unit. Proceeds of these financings were used in part, to retire the Company's revolving credit facility with Macquarie Bank Limited and to retire approximately $1.5 million of the Company's outstanding $2,000,000 convertible debenture issue due in December 2010. (See "Liquidity and Capital Resources" below)

- The Company continued to work closely with the Southwest Regional Partnership ("SWP") to complete the development plan for its Carbon Sequestration Phase III: Deep Saline Sequestration Deployment Project to be sited at Gordon Creek. This project will be funded approximately 80% by the US Department of Energy ("DOE") and 20% by the other participants, including the Company, The University of Utah through the Utah Science Technology And Research initiative ("USTAR") and the New Mexico Tech – Petroleum Recovery Research Center. It is anticipated that the project will represent an investment in excess of twenty million (US$20,000,000) in wells, facilities and infrastructure to be situated at Gordon Creek. Work during the last few months, including the current quarter, has consisted of further design refinement and costing analysis, as well as navigating the project through the extensive DOE approval process. It is anticipated that the approval process will be completed in the first quarter of fiscal 2012 (ending April 2011) to allow the commencement of operations in the second quarter.

- The Company signed an agreement with Ascent Exploration, Inc. ("Ascent") of Southlake, Texas to farm out roughly one-half of the Company's Weston County, Wyoming oil project acreage. Ascent has completed its legal due diligence and paid the first acreage bonus stipulated in the farm out agreement. Ascent has advised Thunderbird that it currently plans to drill the first well on the project in the second quarter of the upcoming fiscal year.

Natural gas production at Gordon Creek during the first nine months of the current fiscal year declined approximately 5% as compared to the production during the first nine months of the previous fiscal year. A pump change operation carried out on one of the Company's producing wells during the current quarter contributed to this decline. The average price realized for natural gas during the nine months was $3.54 per Mcf as compared to $2.35 per Mcf during the first nine months of the previous fiscal year. A decline in third party water disposal revenues during the current year contributed to a 14% overall decline in gross revenues from $985,753 to $856,599. Operating income for the nine months declined roughly 27% from $344,907 to $251,742.

Average natural gas prices realized by the Company during the quarter were US$3.31 (US$3.54 for the nine months) as compared to US$2.57 (US$2.35 for the comparable nine months) of the previous fiscal year. Increased pricing realized by the Company during the current year is largely due to generally stronger gas prices in the Rocky Mountain region where the completion of the Rocky Mountain Express ("REX") pipeline has increased take away capacity and thereby reduced the basis price differentials attributable to gas in the region. The Company also forward sold approximately one-half of its net production for a 12 month period ended October 31, 2010 at a price of $4.25 per Mcf.

Overall US demand for natural gas has strengthened during calendar 2010 as the general economy began to recover, however overall supply of gas has also increased with an increase in the number of gas drilling rigs in operation. These factors make it difficult to predict future gas price directions. Currently, the total amount of gas in underground storage in the United States is roughly 1% less than it was at this time last year, but approximately 10% above comparable five year average storage levels.

RESULTS OF OPERATIONS

	Three Months Ended			Nine Months Ended	
	October 31, 2010	July 31, 2010	October 31, 2009	October 31, 2010	October 31, 2009
Operating Income[1]	**53,108**	**74,126**	**70,153**	**251,742**	**344,907**
General and administrative	(408,592)	(199,172)	(160,204)	(753,892)	(585,978)
Interest and debt service costs	(414,028)	(153,963)	(150,932)	(717,819)	(420,795)
Interest income	167	219	6,861	599	9,473
Funds Flow From Operations[1]	**(769,345)**	**(278,790)**	**(234,122)**	**(1,219,370)**	**(652,393)**
Non-cash operating items:					
Accretion and debt service costs	(23,856)	(87,942)	(100,488)	(202,742)	(313,887)
Depletion, depreciation and accretion	(111,958)	(110,899)	(154,269)	(333,633)	(482,960)
Stock-based compensation	(55,995)	(55,995)	(18,074)	(167,985)	(65,134)
Unrealized foreign exchange (gain) loss	5,136	(7,042)	5,823	23,945	60,529
Net loss for the period	**(956,018)**	**(540,668)**	**(501,130)**	**(1,899,785)**	**(1,453,845)**

(1) "Operating income" and "funds flow from operations" are non-GAAP terms and may not be comparable with the calculation of similar measures for other entities. Operating income is equal to petroleum and natural gas sales minus royalties, operating costs, while funds flow from operations represents cash flow from operations before net changes in operating working capital accounts. Refer to the advisory on non-GAAP measures at the end of this MD&A.

Operating Income Items

Sales Volumes

During the three months ended October 31, 2010 the Company's sales volume averaged 615 mcf/d and 4 bbls/d respectively. This compared to average daily sales volumes of 648 mcf/d and 2 bbls/d experienced in the three months period ended July 31, 2010 and 690 mcf/d and 5bbls/day in the three months ended October 31, 2009

Production Summary

The following table summarizes the production for the third quarter of fiscal 2011 and fiscal 2010:

	Three months ended October 31,		Nine months ended October 31,	
	2010	2009	2010	2009
Production:				
Natural gas (mcf)	56,322	63,543	176,000	185,727
Oil (bbls)	322	421	811	1,300
Total (BOE) (6:1)	9,754	11,012	30,144	32,255
Production split:				
Natural gas (%)	97%	96%	98%	96%
Oil (%)	3%	4%	2%	4%

RESULTS OF OPERATIONS continued

Average Realized Price

The following table summarizes the average realized price for the third quarter of fiscal 2011 and fiscal 2010:

		Three months ended October 31,				Nine months ended October 31,			
			2010		2009		2010		2009
Exchange Rate	*US$/Cdn$*		*0.9697*		*0.9304*		*0.9675*		*0.8734*
Natural gas (mcf)	*US$/Mcf*	*$*	*3.31*	*$*	*2.57*	*$*	*3.54*	*$*	*2.35*
Oil (bbls)	*US$/bbls*	*$*	*70.10*	*$*	*63.44*	*$*	*71.05*	*$*	*52.15*

Revenues, Royalties & Operating Costs

	Three Months Ended						Nine Months Ended			
		October 31, 2010		July 31, 2010		October 31, 2009		October 31, 2010		October 31, 2009
Revenues	$	271,558	$	280,566	$	305,716	$	856,599	$	985,753
Royalties expense		39,681		57,120		35,382		145,364		119,097
Operating costs		178,769		149,320		200,181		459,493		521,749
Operating Income(1)	$	53,108	$	74,126	$	70,153	$	251,742	$	344,907

(1) Refer to the advisories on non-GAAP measures at the end of this MD&A.

Revenues

Third quarter revenues decreased 3% over the second quarter of 2011 and 11% over the third quarter of fiscal 2010. The decrease over the second quarter of fiscal 2010 is primarily due to the decrease in gas production as well as a decline in gas prices. The decrease over the corresponding period in 2010 is primarily attributed to a decrease in revenue from third party water disposal revenue.

Royalties

Royalties as a percentage of petroleum and natural gas sales were 18% for the third quarter compared to 25% the second quarter and 17% for the third quarter of fiscal 2010. The decrease in royalties during the current quarter over the previous quarter of fiscal 2011 was due to a Utah State period end annual required minimum royalty charge that was incurred in the second quarter of fiscal 2011. Royalties vary for each producing well and therefore as a percentage of petroleum and natural gas sales will fluctuate from time to time depending on the production from each well during the respective period.

Operating costs

Operating expenses include all normal operating costs as well as work over costs for both the Gordon Creek and the Rush County projects. Costs in the third quarter ($178,769) increased 20% over the second quarter ($149,320) of the year due in part to the replacement of a down hole pump on one producing well, as well as the completion of periodic mandated pressure tests completed on a number of standing wells. However, third quarter costs decreased 11% as compared to the operating costs in the third quarter of the prior fiscal year.

OTHER INCOME STATEMENT ITEMS

General and administrative

General and administrative costs include such items as office rent, accounting fees, legal fees, professional and consulting fees, filing fees, salaries and wages, transfer agent fees, travel costs, and investor relations, as well as general office expenses.

	Three Months Ended			Nine Months Ended	
	October 31, 2010	**July 31, 2010**	**October 31, 2009**	**October 31, 2010**	**October 31, 2009**
Reported amount	$ 408,592	$ 199,172	$ 160,204	$ 753,892	$ 585,978
G&A ($/boe)	$ 41.89	$ 19.77	$ 14.55	$ 25.01	$ 18.17

G&A expenses increased considerably in the third quarter of fiscal 2011 as compared to the immediately preceding quarter and compared to the third quarter of fiscal 2010. The higher G&A expenses incurred in the current quarter was attributable to legal fees and related expenses incurred with regards to the issuance of the three year gas linked debentures during the current quarter.

Interest, accretion and debt service costs

Interest, accretion and debt service costs increased over the second quarter of fiscal 2011 and over the third quarter of fiscal 2010. The increase in interest, accretion and debt service costs was primarily due to the costs associated with the three year gas linked debentures issued during the period. Interest charges for the quarter ended October 31, 2010 include interest incurred on the credit facility with Macquarie Bank of $49,061 (2009 - $75,071) interest paid or accrued on short term debt and promissory notes of $31,866 (2009 - $15,368) and interest paid on convertible debentures of approximately $60,493 (2009 - $60,493). Accretion costs of approximately $23,857 (2009 - $20,198) relate to the accretion on the convertible debentures. Debt service costs of approximately $272,607 (2009 - $80,290) relate primarily to commissions and other debenture issue costs incurred during the quarter. Debt service costs in the third quarter of 2010 pertained to the fair value of warrants issued to Macquarie Bank under the now retired revolving credit facility.

	Three Months Ended			Nine Months Ended	
	October 31, 2010	**July 31, 2010**	**October 31, 2009**	**October 31, 2010**	**October 31, 2009**
Reported amount	$ 437,884	$ 241,905	$ 251,420	$ 920,561	$ 734,682
Expense per sales volume ($/boe)	$ 44.89	$ 24.01	$ 22.83	$ 30.54	$ 22.78

OTHER INCOME STATEMENT ITEMS continued

Depletion, depreciation and accretion

	Three Months Ended			Nine Months Ended	
	October 31, 2010	July 31, 2010	October 31, 2010	October 31, 2010	October 31, 2009
Reported amount	$ 111,958	$ 110,899	$ 154,269	$ 333,633	$ 482,960
Expense per sales volume ($/boe)	$ 11.48	$ 11.01	$ 14.01	$ 11.07	$ 14.97

The Company follows the full-cost method of accounting for oil and gas properties, whereby all capitalized costs relating to the acquisition, exploration and development of oil and gas activities are amortized against future income using the unit-of-production method. This method is based on production volumes before royalties in relation to total estimated proved reserves as determined by independent engineers. MHA estimated the Company's reserves as of January 31, 2010 in accordance with NI 51-101.

Unrealized foreign exchange gain

At the end of the third quarter the Company had unrealized foreign exchange gain of $23,945. This gain pertains to the translation of short-term debt and promissory notes denominated in U.S. currency. The increase in unrealized foreign exchange gain is due to a stronger Canadian dollar at October 31, 2010 than at January 31, 2010.

Stock-based compensation

In accordance with CICA Handbook section 3870, the fair value of each option granted is estimated on the date of the grant using the Black-Scholes option pricing model with the following weighted average assumptions:

	October 31, 2010	January 31, 2010
Weighted average fair value per share	$ 0.23	$ 0.20
Dividend yield	0%	0%
Interest rate	2.28%	2.28%
Expected life	4.45 years	4.45 years
Volatility	144%	144%

RISKS AND TRENDS

Demand for natural gas has traditionally been highly cyclical during any given year and somewhat predictable. Demand for, and pricing of, natural gas has traditionally been highest during the coldest months of winter. The primary driver for this cyclicality is the need for residential and commercial heating. Because natural gas is increasingly being used to generate electricity, increased electrical demand often means increased natural gas demand and pricing. This results in a smaller spike in natural gas demand during the warmest months of the year, as electrical demand for space cooling increases. Accordingly, the spring and fall "shoulder seasons" are typically becoming the periods of lowest natural gas prices. The magnitude of this summer spike in natural gas prices is expected to increase in future years as natural gas continues to replace coal as a clean source of electrical power generation. In addition, issues relating to pipeline capacity constraints, pipeline maintenance and unscheduled shut-downs, can temporarily impact regional pricing.

Year over year, North American natural gas pricing can be volatile and can be impacted by macro economic factors effecting industrial demand, weather patterns, exploration activities and liquefied natural gas imports.

Although the Company has no set policy concerning hedges, the management may utilize various techniques to mitigate financial risks including hedging contracts, other financial instruments, and/or fixed price forward sales contracts to reduce corporate risk in certain situations. At October 31, 2010 the Company does not have a fixed price contract in place.

Oil and natural gas operations involve many risks that even a combination of experience and knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Company depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Company may have at any particular time and the production there from will decline over time as such existing reserves are exploited. A future increase in the Company's reserves will depend not only on the Company's ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that further commercial quantities of oil and natural gas will be discovered or acquired by the Company.

The Company's principal risks include finding and developing economic hydrocarbon reserves efficiently and the ability to fund the required capital programs. The Company's needs for capital are both short and long-term in nature. The Company anticipates that future capital requirements will be funded through a combination of internal cash flow, debt and equity financing. There is no assurance that debt and equity financing will be available on terms acceptable to the Company to meet its capital requirements. If any components of the Company's business plan are missing, the Company may not be able to exercise the entire business plan.

These risk factors should not be construed as exhaustive. There are numerous factors, both known and unknown, that could cause results or events to differ materially from forecast results.

LIQUIDITY AND CAPITAL RESOURCES

The Company's source of funding includes the issuance of equity securities for cash, primarily through private placements and debt financing. The Company has issued common shares pursuant to private placement financings and exercise of warrants and options. The Company's access to exploration financing when the financing is not transaction specific is always uncertain. There can be no assurance of the continued access to significant equity financing.

During the nine months ended October 31, 2010, the Company's additions to its oil and gas properties totalled $197,511 (2009 - $337,735).

At October 31, 2010, the Company had cash of $98,732 and a working capital deficiency of $1,146,853. The working capital deficiency includes a current liability of $2,152,516 which consists of accounts payable, amounts due to related parties, short-term debt and convertible debentures payable.

The Company has no "purchase obligations" defined as any agreement to purchase goods or services that is enforceable and legally binding on the Company that specifies all significant terms, including fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the proximate timing of the transaction.

The Company had no commitments for capital expenditures as of October 31, 2010. The Company has no lines of credit or other sources of financing which have been arranged at this time, other than those listed below.

Revolving Credit Facility

During the quarter, the Company repaid and retired its revolving credit facility with Macquarie Bank Limited with the proceeds of the three year natural gas linked debenture financing.

Convertible debentures

Debentures with the face value of $515,000 issued in December of 2008 at 12% interest, paid quarterly, are still outstanding and due in December 2010. The Company may repay the debentures at any time, but until repaid, the debentures are convertible at the holders' option into common shares of the Company at a price of $0.25 per share thereafter until maturity on December 15, 2010. The Company has made an offer to the existing debenture holders to extend the due date until June 15, 2011 and reduce the conversion price to $0.15 per share until the extended maturity date.

Long-term debt

On October 29, 2010, the Company issued three year, secured, natural gas linked debenture totalling $7,342,500, pursuant to a first tranche closing of a proposed $7,500,000 issue. The debentures bear interest at a base rate of 15% per annum with an adjustment provision whereby a 1% interest is added each quarter for every US$0.50 by which the price of natural gas as published by the Henry Hub exceeds US$5.00 capped at 25% per annum. One-half of each quarterly interest payment will be paid in fully paid common shares of the Company at a deemed price per interest share equal to the greater of (i) a 10% discount to the volume weighted average trading price of the Company's common shares on the TSX Venture Exchange over the quarter and (ii) the discounted market price of the Company's common shares, as determined pursuant to the TSX Venture Exchange policies. The purchasers of the gas linked debentures were also issued two detachable transferable warrants for every $1.00 of principal amount to purchase up to 14,685,000 common shares of the Company at escalating prices between $0.30 and $0.50 per share until October 31, 2013. The Company paid a 7.5% finder's fee in respect of a portion of the debenture issuance and issued non-transferable finder's warrants to purchase up to 1,381,250 common shares of the Company at a price of $0.20 per share until October 31, 2013. All securities issued pursuant to the first tranche closing are subject to hold periods in Canada expiring March 1, 2011.

TRANSACTIONS WITH RELATED PARTIES

Koele Capital Corp. ("Koele") of which the President and CEO is a shareholder, was paid $22,500 in consulting fees for the quarter. The Company has an ongoing contractual arrangement with Koele to pay consulting fees of $7,500 per month

Westrich Resources Inc. ("Westrich") of which the COO is a shareholder, was paid $23,050 in consulting fees for the quarter. The Company pays Westrich a daily consulting fee which varies month to month, that averages approximately $10,000 per month. Westrich was also paid $6,165 by way of a partial reimbursement of rent, supplies and computer expenses during the quarter, pursuant to a cost sharing arrangement between the two companies.

Bar Anchor Five Ranch Ltd. ("Bar Anchor"), of which the Chairman is a director, was accrued $15,000 in consulting fees for the quarter.

Thunderbird Films Inc, a company that shares common directors with the Company, was accrued $29,591 by way of a partial reimbursement of accounting fees, office reception, rent and supplies during the quarter pursuant to a cost sharing arrangement between the two companies.

Amounts due to related parties include an unsecured short-term loan payable and accrued interest to directors of the Company for $47,000 (2009 - $214,444). The loans carry a 12% interest rate and are payable on demand. Also included is $159,945 (2009 - $418,045) due to directors and companies with common directors.

QUARTERLY FINANCIAL INFORMATION *(unaudited)*

Income Statement:	**Q3 2011**	**Q2 2011**	**Q1 2011**	**Q4 2010**	**Q3 2010**	**Q2 2010**	**Q1 2010**	**Q4 2009**
Net Revenues after Royalties	231,878	223,446	255,911	318,250	270,334	335,972	260,350	382,383
Expenses	1,187,896	764,114	666,571	893,922	771,464	836,005	713,032	1,227,024
Net loss for the period	(956,018)	(540,668)	(410,660)	(575,672)	(501,130)	(500,033)	(452,682)	(844,641)
Basic and diluted loss per share	(0.014)	(0.008)	(0.006)	(0.009)	(0.007)	(0.008)	(0.007)	(0.013)
Weighted average number of shares outstanding (thousands)	69,864	67,079	67,079	67,079	67,079	67,079	67,079	67,079

CRITICAL ACCOUNTING ESTIMATES

The Company's accounting policies are described in Note 2 of its audited consolidated financial statements for the year ended January 31, 2010. Preparing financial statements requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. These estimates relate primarily to the future development costs associated with proved undeveloped reserves, reserve volumes, future production and revenues, future costs associated with asset retirement obligations and stock based compensation. The Company has its oil and gas reserves, future development costs and future cash flows from those reserves evaluated and reported on by MHA, independent petroleum reserve engineering consultants. The estimation of these amounts is a subjective process based on engineering data, forecasted prices and production levels and the timing of expenditures. All of these estimates are subject to numerous uncertainties and various interpretations, and consequently will change over time to reflect updated information as it is received.

No changes have been made to the Company's critical accounting policies and estimates in the nine months ended October 31, 2010.

SIGNIFICANT ACCOUNTING PROUNOUNCEMENTS

Future Accounting Changes

Section 1601, "Consolidated Financial Statements" in combination with Section 1602 "Non-Controlling Interest", replace Section 1600 "Consolidated Financial Statements". Section 1601 establishes standards for the preparation of consolidated financial statements and specifically addresses consolidation accounting following a business combination that involves the purchase of an equity interest in one company by another. CICA 1602 establishes standards for accounting for noncontrolling interest in a subsidiary in consolidated financial statements subsequent to a business combination. These sections apply to all financial statements for fiscal years beginning on or after January 1, 2011, with early adoption permitted. There is no impact on the Company's financial statements at this time.

Section 1582, "Business Combinations", establishes principles for the measurement of assets, liabilities and contingencies acquired at fair value, and recognizing acquisition-related and reorganization costs separately from business combination within the statement of operations. These recommendations are effective for business combinations occurring after January 1, 2011, with early adoption permitted. There is no impact on the Company's financial statements at this time.

INTERNATIONAL FINANCIAL REPORTING STANDARDS ("IFRS")

Refer to disclosures provided in the January 31, 2010 MD&A with respect to a discussion and status of the Company's IFRS implementation plan. The Company is currently in the initial review phase.

FORWARD LOOKING STATEMENTS

This discussion includes certain statements that may be deemed "forward-looking statement". Forward-looking statements or information do not relate strictly to historical or current facts, and can be identified by words such as "anticipate", "continue", "estimate", "expect", "forecast", "may", "will", "plan", "project", "should", "believe", "intend", or similar expressions. These statements represent managements' reasonable projections, expectations and estimates as of the date of this document, but undue reliance should not be placed upon them as they are derived from numerous assumptions. These assumptions are subject to known and unknown risks and uncertainties, including the business risk discussed in the MD&A, which may cause actual performance and financial results to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements.

FORWARD LOOKING STATEMENTS continued

Such forward-looking statements or information are based on a number of assumptions which may prove to be incorrect. In addition to the other assumptions identified in this document, assumptions have been made regarding, among other things:

- Future oil and gas supply and prices;
- Drilling and operational results consistent with expectations;
- The ability for the Company to obtain financing on acceptable terms;
- Currency, exchange and interest rates;
- Cash flow consistent with expectations;
- The ability of the Company to obtain equipment, services and supplies in a timely manner to carry out its activities;

The forward looking information in this document is subject to significant risks and uncertainties and is based on a number of material factors and assumptions which may prove to be incorrect; including but not limited to the following assumptions:

- Normal risks common to the petroleum and natural gas industry including various operational risk in exploring for, developing and producing petroleum and natural gas and market demand
- Risks and uncertainties involving geology of oil and gas deposits
- Revisions, amendments or changes to capital expenditure plans including exploration, development and exploitation projects
- Uncertainties as to the availability and cost of appropriate financing alternatives on acceptable terms, including the Company's ability to extend its credit facility on an ongoing basis
- Potential changes in income tax regulations, governmental policies, rules, practices or approval process changes, or delays, or enhancements
- Ability to attract and retain qualified professional employees
- Fluctuations in oil and gas prices, foreign currency exchange rates and interest rates
- The uncertainty of reserve estimate and reserve life
- The uncertainty of estimates and projections relating to future production, costs and expenses
- Health, safety and environmental risks

Statements relating to "reserves" or "resources" are by their nature deemed to be forward-looking statements, as they involve the implied assessment based on certain estimates and assumptions that the resources and reserves described can be profitably produced in the future.

Although the company believes the expectations expressed in such forward-looking statements or information are based on reasonable assumptions, such statements are not guarantees of future performance and actual results or developments may differ materially from those in the forward-looking statements. Accordingly, readers should not place undue reliance on forward-looking information.

The forward-looking statements or information contained in this document represent our views as of the date hereof and as such information should not be relied upon as representing our views as of any date subsequent to the date of this document. The Company undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

Non-GAAP Measures
In this document, the Company uses the terms "funds flow from operations" and "operating income", collectively the "Non-GAAP measures, as indicators of the Company's financial performance. The Non-GAAP measures do not have a standardized meaning prescribed by Canadian generally accepted accounting principles ("GAAP") and therefore are unlikely to be comparable to similar measures presented by other entities.

"Funds flow from operations" refers to the cash flow from operating activities before net changes in operating working capital. The most direct comparable measure to "funds flow from operations" calculated in accordance with GAAP is the cash flow from operating activities. "Funds flow from operations" can be reconciled to cash flow from operating activities by adding (deducting) the net change in working capital as shown in the consolidated statements of cash flow.

"Operating income" is equal to petroleum and natural gas sales minus royalties and operating costs. Management believes that the Non-GAAP measures provide useful information to investors as indicative measures of performance.

Investors are cautioned that the Non-GAAP measures should not be considered in isolation or construed as alternatives to their most directly comparable measure calculated in accordance with GAAP, as set forth above, or other measures of financial performance calculated in accordance with GAAP.

BOE Presentation
Barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of gas ("Mcf") to one barrel of oil ("bbl") (6 Mcf: 1 bbl) is used as an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All boe conversions in this report are derived by converting natural gas to oil in the ratio of six Mcf of gas to one barrel of oil. Readers should be aware that historical results are not necessarily indicative of future performance.

DISCLOSURE OF OUTSTANDING SHARE DATA

As at December 21, 2010 the Company had the following common shares and stock options outstanding:

Common Shares	71,912,826
Share Purchase Warrants	21,149,584
Stock Options	5,415,000

There are no shares held in escrow.

As of December 21, 2010, there were $515,000 of two-year convertible debentures outstanding, convertible to common shares at rates of $0.25 per share. (See "Liquidity and Capital Resources – Convertible Debentures")

"CAMERON WHITE"
Cameron White, Chief Executive Officer

"STEPHEN CHEIKES"
Steven Cheikes, Director