



YEAR ENDED JANUARY 31, 2010
MANAGEMENT DISCUSSION AND ANALYSIS

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 May 20, 2010, and is for the years ended January 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 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 May 20, 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

During the past year, the Company completed an extensive study of the Gordon Creek geology and production history, as well as the history of neighboring Drunkards Wash and Clear Creek fields. As a result, the Company has gained a greater understanding of the geology at Gordon Creek and, in particular, the depositional characteristics of the Ferron Sandstone and Coals throughout the region. This study, combined with an extensive review of the geology and operating practices at the neighboring Drunkards Wash field have led the Company's management to the conclusion that the Gordon Creek field has not been operated in accordance with best practices and there is considerable room for optimization in existing wells and new drilling locations. During the year, the Company also created an extensive Gordon Creek development plan and focused its efforts on developing a strategy to secure the capital necessary to carry out the development plan.

On December 21, 2009, the Company announced two letters of intent ("LOI") with independent third parties collectively providing for the investment of up to US\$40 million at Gordon Creek, commencing in 2010. Both agreements are subject to various conditions precedent including further due diligence, formal documentation and financing.

The first LOI involves Thunderbird's participation with a group called the Southwest Regional Partnership ("SWP") in 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 Thunderbird, 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 US\$20 million in wells, facilities and infrastructure to be situated at Gordon Creek. The project is currently at an advanced design stage, although final designs and participation remain subject to final DOE approvals. The first major step in the project will be to drill a deep (3,650 meter) CO₂ source well in the southern portion of the Gordon Creek lands as early as the third quarter of this year.

The second LOI contemplates an investment of up to US\$20 million by a Houston, Texas based private company (“HoustonCo”) to fund a mutually agreed development plan. HoustonCo will earn various interests at certain stages of development, resulting in an overall 50% working interest (75% working interest before payout on earning wells) in the Gordon Creek property. Thunderbird will retain ownership of its existing facilities and infrastructure and will charge mutually agreed fees for gas gathering, compression and water treating and disposal. HoustonCo has completed its due diligence on the project and is currently in the funding phase. Subject to the timely completion of HoustonCo’s financing, Thunderbird anticipates kicking off the joint venture in the third quarter with a 15 well drilling program. The joint venture remains subject to financing and to formal documentation.

MHA Petroleum Consultants Inc. (“MHA”) of Denver, Colorado prepared a reserve report (the “MHA Report”) on the Company’s oil and gas interests in accordance with NI 51-101 effective January 31, 2010. Specifically, the MHA Report covers the Company’s interests in the Gordon Creek natural gas project and its 50% working interest in the Rush County, Kansas light oil project. MHA estimated the Company’s total proved plus probable (2P) reserves at 30.92 Bcf of natural gas. The MHA Report estimated the Net Present Value before tax of Future Net Revenue discounted at 10% (PV10) of the Company’s combined oil and gas interests at US\$49.7 million, using forecasted prices and costs.

Production at Gordon Creek during the fourth quarter was roughly equal to production during the fourth quarter of the prior year. Production for the year ended January 31, 2010 also represented a roughly 15% increase over first nine months of the previous fiscal year. These increases were almost entirely a result of field optimization with no new wells drilled or other major capital expenditures.

Natural gas prices recovered during the fourth quarter, however, on balance prices realized by the company during the year averaged \$2.65 compared to an average price of \$5.99 which was realized during the prior year. Economic indicators continue to suggest that the general economic activity is recovering, which may lead to higher prices for gas over the next few quarters. There was a dramatic reduction in the number of active drilling rigs in the US and Canada in calendar 2009 and there has only been a very moderate recovery since. A decrease in drilling rig activity is traditionally a leading indicator of supply declines. However, gas presently in storage remains well above five year averages; therefore, short term prices are forecast to remain relatively soft. In anticipation of this, the Company entered into a fixed price forward sale of 10,000 Mcf/month (roughly 40% of the Company’s current net production) for the period November 1, 2009 to October 31, 2010.

Short-term constraints on pipeline capacity have historically contributed to sharp negative price differentials for natural gas produced in the US Rocky Mountain region, due in part to restricted take-away capacity to move natural gas from the Rockies to the eastern United States. Price differentials between Henry Hub and the main Rockies hubs in Wyoming have often been US\$1 to US\$2 and periodically much higher. The third and final phase of the REX pipeline was completed during the third quarter which has substantially increased this take away capacity and lowered the average price differentials to the US\$0.30 to US\$0.50 range. The expectation is that these reduced differentials will remain in place for the foreseeable future, resulting in higher gas pricing for the Company.

SELECTED ANNUAL INFORMATION

The following table set forth consolidated financial data prepared in accordance with Canadian GAAP for our last three fiscal years:

	January 31, 2010	January, 31, 2009	January, 31, 2008
Total revenues	1,184,906	1,303,712	864,404
Net loss	(2,029,517)	(2,693,700)	(2,403,290)
Basic and diluted loss per share	(0.03)	(0.06)	(0.06)
Total assets	10,779,821	12,569,542	9,757,854
Total long-term financial liabilities	212,394	1,819,804	3,634,162

The Company has not declared any cash dividends since inception.

RESULTS OF OPERATIONS

	Three Months Ended			Years Ended		
	January 31, 2010	October 31, 2009	January 31, 2009	January 31, 2010	January 31, 2009	January 31, 2008
Operating Income⁽¹⁾	133,823	70,153	20,902	478,730	286,588	173,263
General and administrative	(195,616)	(160,204)	(405,057)	(781,594)	(1,170,030)	(1,371,051)
Interest and debt service costs	(151,840)	(150,932)	(135,614)	(572,636)	(478,677)	(390,514)
Interest income	403	6,861	816	9,876	4,445	3,873
Funds Flow From Operations⁽¹⁾	(213,230)	(234,122)	(518,953)	(865,624)	(1,357,674)	(1,584,429)
<i>Non-cash operating items:</i>						
Accretion and debt service costs	(96,315)	(100,488)	(30,800)	(410,201)	(443,260)	(101,527)
Depletion, depreciation and accretion	(124,667)	(154,269)	(148,872)	(607,627)	(633,157)	(444,242)
Stock-based compensation	(141,640)	(18,074)	(61,975)	(206,774)	(175,807)	(273,092)
Unrealized foreign exchange gain (loss)	180	5,823	(84,043)	60,709	(83,802)	-
Net loss for the period	(575,672)	(501,130)	(844,643)	(2,029,517)	(2,693,700)	(2,403,290)

⁽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 and year ended January 31, 2010 the Company's gas sales volume averaged 693 Mcf/d and 684 Mcf/d respectively. This compared to average daily gas sales volumes of 630 Mcf/d and 560 Mcf/d experienced in the three months and year ended January 31, 2009. The Company's oil sales volume for the same periods in fiscal 2010 averaged 4 bbls/d, down from 7bbls/d and 8 bbls/d experienced in the respective three and twelve months periods ended January 31, 2009. Daily sales volumes were consistent throughout fiscal 2010. Sales volumes increased 17% over fiscal 2009 as the result of optimizing field operating practices in the current year.

Production Summary

The following table summarizes the production for the fourth quarter and year-end of fiscal 2010 and 2009:

	Three months ended 2010	January 31, 2009	Year ended 2010	January 31, 2009
Production:				
Natural gas (Mcf)	63,761	57,967	249,488	204,512
Oil (bbls)	372	628	1,672	2,979
Total (BOE) (6:1)	10,999	10,289	43,253	37,064
Production split:				
Natural gas (%)	97%	94%	96%	92%
Oil (%)	3%	6%	4%	8%

Average Realized Price

The following table summarizes the average realized price for the fourth quarter and year-end of fiscal 2010 and 2009:

		Three months ended January 31,		Year ended January 31,	
		2010	2009	2010	2009
Exchange Rate	US\$/Cdn\$	0.9484	0.8150	0.8877	0.9220
Natural gas (Mcf)	US\$/Mcf	\$ 3.55	\$ 2.50	\$ 2.66	\$ 4.33
Oil (bbls)	US\$/bbls	\$ 69.07	\$ 41.03	\$ 55.91	\$ 91.31

Revenues, Royalties & Operating Costs

	Three Months Ended			Year Ended	
	January 31, 2010	October 31, 2009	January 31, 2009	January 31, 2010	January 31, 2009
Revenues	\$ 373,125	\$ 305,716	\$ 444,963	\$ 1,358,878	\$ 1,565,474
Royalties expense	(54,875)	(35,382)	(62,581)	(173,972)	(261,762)
Operating costs	(184,427)	(200,181)	(361,480)	(706,176)	(1,017,124)
Operating Income ⁽¹⁾	\$ 133,823	\$ 70,153	\$ 20,902	\$ 478,730	\$ 286,588

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

Revenues

Fourth quarter revenues increased 22% over the third quarter of 2010. The increase was primarily attributable to the increase in oil and gas prices. Fourth quarter revenue decreased 16% compared to the fourth quarter of fiscal 2009. This was primarily due to the third quarter oil revenues for 2009 being recorded in the fourth quarter of 2009, as the revenues were not known until the fourth quarter due to the bankruptcy of Semcrude, the former purchaser of the Company's oil. The revenues for the year are 12% less than fiscal 2009 due to the lower gas and petroleum prices in the current fiscal year.

Royalties

Royalties as a percentage of petroleum and natural gas sales were 19% during the fourth quarter, consistent with the third quarter. Royalties as a percentage of petroleum and natural gas sales were 20% for fiscal 2010 comparable with 22% in the prior fiscal year. Royalties as a percentage of revenues typically varies slightly throughout the year, as the gas royalties charged for the individual wells differs.

Operating costs

Operating expenses include all normal operating costs as well as workover costs for both the Gordon Creek and the Rush County projects. Fourth quarter costs decreased 8% over the third quarter due to late billings of second quarter compressor fees which increased third quarter operating costs. Fourth quarter operating costs decreased 49% from the fourth quarter of fiscal 2009, while the costs for fiscal 2010 decreased 31% over fiscal 2009. The decreases over the prior year corresponding periods were due primarily from minimal workovers being performed in 2010, as compared to the previous 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			Year Ended	
	January 31, 2010	October 31, 2009	January 31, 2009	January 31, 2010	January, 31, 2009
Reported amount	\$ 195,616	\$ 160,204	\$ 405,057	\$ 781,594	\$ 1,170,030
G&A (\$/boe)	\$ 17.79	\$ 14.55	\$ 39.37	\$ 18.07	\$ 31.57

G&A expenses increased 22% in the fourth quarter of fiscal 2010 as compared to the preceding quarter. The higher G&A expenses incurred in the fourth quarter were largely due to additional professional and consulting fees accrued for work relating to the year-end financial statement audit, tax returns and the reserve report.

G&A expenses for the three months and year ended January 31, 2010 were 52% and 33% less than the corresponding periods in fiscal 2009, as administrative duties performed in the US were eliminated in fiscal 2010, in addition to minimal debt issue costs incurred during the year.

Interest, accretion and debt service costs

Interest charges for the year include interest incurred on the credit facility with Macquarie Bank of approximately \$274,012 (2009 - \$231,881) interest paid or accrued on short term debt and promissory notes of approximately \$59,606 (2009 - \$68,412) and interest paid on convertible debentures of approximately \$239,018 (2009 - \$164,204). Accretion costs of approximately \$79,562 (2009 - \$49,656) relate to the accretion on the convertible debentures. Debt service costs of approximately \$330,639 (2009 - \$393,604) relate to the fair value of warrants issued to Macquarie.

	Three Months Ended			Year Ended	
	January 31, 2010	October 31, 2009	January 31, 2009	January 31, 2010	January, 31, 2009
Reported amount	\$ 248,155	\$ 251,420	\$ 166,414	\$ 982,837	\$ 921,937
Expense per sales volume (\$/boe)	\$ 22.56	\$ 22.83	\$ 16.17	\$ 22.72	\$ 24.87

Interest, accretion and debt service costs remained consistent in the third and fourth quarter. The increase in interest, accretion and debt service costs for the fourth quarter of 2010 as compared to the same quarter of 2009 was 49%, primarily related to the fair value of warrants issued to Macquarie. In 2009, the costs had been fully recorded by the end of the third quarter and in 2010 they were spread equally throughout the year. The interest, accretion and debt service costs was 7% higher in fiscal 2010 than fiscal 2009. This was mainly due to interest incurred on the credit facility with Macquarie Bank, which has increased in fiscal 2010 as the interest rate increase of approximately 3% due to a premium over the original contract rates, due to the Company breaching certain financial covenants contained in the loan agreement.

Depletion, depreciation and accretion

	Three Months Ended			Year Ended	
	January 31, 2010	October 31, 2009	January 31, 2009	January 31, 2010	January 31, 2009
Reported amount	\$ 124,667	\$ 154,269	\$ 148,872	\$ 607,627	\$ 633,157
Expense per sales volume (\$/Boe)	\$ 11.33	\$ 14.01	\$ 14.47	\$ 14.05	\$ 17.08

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) loss

At the end of the fourth quarter the Company had minimal unrealized foreign exchange gain, as the exchange rate between the Canadian and US dollar was consistent with the third and fourth quarter. The Company had unrealized foreign exchange gain of approximately \$60,709 for fiscal 2010. 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 January 31, 2010 than at January 31, 2009.

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:

	2010	2009
Weighted average fair value per share	\$ 0.20	\$ 0.21
Dividend yield	0%	0%
Interest rate	2.28%	3.19% - 3.37%
Expected life	4.45 years	4.51 years
Volatility	144%	104%

Commitments

The Company sub-leases its office premises for which minimum lease payments are due as noted below:

Fiscal	Amount
2011	\$ 32,290
2012	21,527
Thereafter	-
	<u>\$ 53,817</u>

RISKS AND TRENDS

Demand for natural gas has traditionally been highly cyclical 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 cyclicity 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.

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 January 31, 2010 the Company had a fixed price contract in place to sell 10,000 Mcf per month at \$4.25 per Mcf (roughly 40% of the Company’s current net production) for the period November 1, 2009 to October 31, 2010.

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.

Safety and Environment

Oil and gas exploration and production can involve environmental risks such as pollution of the environment and destruction of natural habitat, as well as safety risks such as personal injury. The Company conducts its operations with high standards in order to protect the environment and the general public. The Company maintains current insurance coverage for comprehensive and general liability as well as limited pollution liability. The amount and terms of this insurance are reviewed on an ongoing basis and adjusted as necessary to reflect current corporate requirements, as well as industry standards and government regulations.

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 year ended January 31, 2010, the Company's additions to its oil and gas properties totalled \$333,951 (2009 -\$1,368,851).

At January 31, 2010, the Company had cash of \$24,783 (2009 - \$257,553) and a working capital deficiency of \$7,977,884 (2009 - \$5,780,989). The working capital deficiency includes a current liability of \$8,586,820 (2009 - \$6,442,901) which consists of accounts payable, amounts due to related parties, short-term debt and the Company's revolving credit facility. At year-end the Company is not in compliance with all covenants on its revolving credit facility, as a result the loan is in default. The Company has not subsequently received a waiver and the facility may be called by the lenders at anytime, therefore the entire amount of the loan is considered current. This contributes to factors which raise substantial doubt about the Company's ability to continue as a going concern, as discussed in Note 1.

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 January 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

The Company has a long-term financing facility agreement with Macquarie Bank that provides up to a maximum commitment of U.S. \$50 million, subject to an availability limit, for the development of the Company's existing oil and natural gas projects and future acquisitions. The loan's interest rate is due and payable monthly, and at the Company's option, is based on the U.S. Prime Rate plus 0.5% or LIBOR plus 3.5%. The initial availability limit is U.S. \$5,685,000 and will be re-determined by the lender every six months based on reserve estimates provided by independent engineers, subject to certain calculations.

The credit facility operates as a revolving credit line with no principal repayments for the first three years. On December 14, 2010, the credit facility converts to a term loan payable over twenty-four months. The term loan will be fully repaid on December 14, 2012. The facility is secured through a first mortgage and security interests in the Company's oil and gas mineral interests. At January 31, 2010, U.S. \$4,093,733 (Cdn \$4,383,978) is owed under this facility. As noted above, at the year-end the Company is not in full compliance with certain financial covenants contained in the loan agreement and as result the loan is in default. Macquarie Bank has not indicated that it has any present intention to call the loan, but since no waivers have been issued, it may be called at anytime, resulting in the entire amount of the loan being categorized as a current liability. The interest rates that the Company is currently being charged reflect a default premium and are 3% over the original contract rates as described above.

Convertible debentures

Debentures with the face value of \$2,000,000 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.

TRANSACTIONS WITH RELATED PARTIES

Koele Capital Corp. ("Koele") of which the President and CEO is a shareholder, was accrued \$90,000 in consulting fees for the year (\$22,500 in the fourth 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 accrued \$112,050 in consulting fees for the year (\$23,400 in the fourth quarter). The Company pays Westrich a daily consulting fee which varies month to month, that averages approximately \$10,000 per month. Westrich was also accrued \$38,253 by way of a partial reimbursement of rent, supplies and computer expenses during the year (\$7,019 in the fourth 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 paid \$60,000 in consulting fees for the year (\$15,000 in the fourth quarter). The Company has an ongoing contractual arrangement with Bar Anchor to pay consulting fees of \$5,000 per month.

Thunderbird Films Inc, a company that shares common directors with the Company, was accrued \$122,226 by way of a partial reimbursement of accounting fees, office reception, rent and supplies during the year, 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 U.S. \$150,675 (Cdn \$161,358) (2009- U.S. \$334,288 (Cdn \$406,875)) and \$60,318 (2009- \$nil). The loan carries a 12% interest rate and is payable on demand. Also included is \$627,384 (2009 - \$70,805) due to directors and companies with common directors.

QUARTERLY FINANCIAL INFORMATION *(unaudited)*

Income Statement:	Q4 2010	Q3 2010	Q2 2010	Q1 2010	Q4 2009	Q3 2009	Q2 2009	Q1 2009
Net Revenues after Royalties	318,250	270,334	335,972	260,350	382,383	223,796	305,669	391,864
Expenses	893,922	771,464	836,005	713,032	1,227,024	1,061,431	893,187	815,770
Net loss for the period	(575,672)	(501,130)	(500,033)	(452,682)	(844,641)	(837,635)	(587,518)	(423,906)
Basic and diluted loss per share	(0.009)	(0.007)	(0.008)	(0.007)	(0.013)	(0.012)	(0.009)	(0.010)
Weighted average number of shares outstanding (thousands)	67,079	67,079	67,079	67,079	67,079	67,079	62,738	50,227

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 three months and year ended January 31, 2010.

Oil and Natural Gas Properties

Under NI 51-101, "proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. In accordance with this definition, the level of certainty targeted by the reporting corporation should result in at least a 90% probability that the quantities actually recovered will equal or exceed the estimated reserves. In the case of "probable" reserves, which are obviously less certain to be recovered than proved reserves, NI 51-101 states that it must be equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. With respect to the consideration of certainty, in order to report reserves as proved plus probable, the reporting company must believe that there is at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves. The implementation of NI 51-101 has resulted in a rigorous and uniform standard of reserve evaluation.

The oil and natural gas reserve estimates are made using all available geological and reservoir data as well as historical production data. Estimates are reviewed and revised as appropriate. Revisions occur as a result of changes in prices, costs, fiscal regimes, reservoir performance or a change in the Company's plans.

The Company uses the full cost method of accounting for exploration and development activities. In accordance with this method of accounting, all costs associated with exploration and development are capitalized whether or not the activities funded were successful. The aggregate of net capitalized costs and estimated future development costs, less estimated salvage values, is amortized using the unit-of production method based on estimated proved oil and natural gas reserves. An increase in estimated proved oil and natural gas reserves would result in a corresponding reduction in depletion expense. A decrease in estimated future development costs would result in a corresponding reduction in depletion expense.

Impairment of Oil and Natural Gas Assets

The Company is required to review the carrying value of all oil and natural gas assets for potential impairment. Impairment is indicated if the carrying value of the oil and natural gas assets is not recoverable by the future undiscounted funds from operations. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the oil and natural gas asset is charged to earnings. The assessment of impairment is dependent on estimates of reserves, production rates, prices, future costs and other relevant assumptions. The Company has performed a ceiling test in the current year and concludes that there is no impairment at January 31, 2010.

Asset Retirement Obligations

The Company is required to provide for future removal and site restoration costs. The Company must estimate these costs in accordance with existing laws, contracts or other policies. The fair value of the liability of \$388,201 (US\$362,500) for the Company's asset retirement obligation is recorded in the period in which it is expected to be incurred between 2008 and 2023, discounted to its present value using the Company's 8% discount rate. The offset to the liability is recorded in the carrying amount of oil and natural gas properties. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to earnings in the period. Revisions to the estimated timing of funds from operations or to the original estimated undiscounted cost could also result in an increase or decrease to the obligation. Actual costs incurred upon settlement of the retirement obligation are charged against the obligation to the extent of the liability recorded.

Stock-Based Compensation

The Company uses the fair value method for valuing stock option grants. The fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model. A zero dividend yield is used as the Company does not issue dividends; the volatility is a calculation based on past trading history; the expected life is calculated based on the Company's historical weighted average exercise period, and the risk-free rate is from the Bank of Canada. An increase in dividends would decrease the option expense and an increase in the volatility or the risk-free rate would increase the calculated expense.

Income Taxes

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulation often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated in the Company's notes to the financial statements.

ADOPTION OF NEW ACCOUNTING POLICIES

The following accounting pronouncements have been adopted for the current year.

Section 3064, "Goodwill and Intangible Assets", establishes revised standards for recognition, measurement, presentation and disclosure of goodwill and intangible assets. The standard also harmonizes Canadian standards with IFRS and applies to interim and annual financial statements for fiscal years beginning on or after October 1, 2008. Adoption of this standard has been applied retroactively and has had no impact on the Company's financial statements.

Section 3862, "Financial Instruments – Disclosures", establishes enhanced disclosures on liquidity risk and requires disclosures on fair value measurements of financial instruments. These requirements harmonize Canadian standards with IFRS and apply to annual financial statements for the fiscal years ending after September 30, 2009.

SIGNIFICANT ACCOUNTING POUNDCEMENTS

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")

The CICA's Accounting Standards Board confirmed that the International Financial Reporting Standards ("IFRS") will replace Canadian generally accepted accounting principles in 2011 for profit oriented Canadian publicly accountable enterprises. The Company will be required to report according to IFRS standards for the year ended January 31, 2012. The Company continues to monitor and assess the impact of convergence of Canadian GAAP and IFRS. The Company is following a three-phase transition plan: initial review and assessment, in-depth analysis, and implementation. The Company is currently in the initial review phase.

The second phase is planned to commence the third fiscal quarter of 2011. In this phase, the Company will perform a detailed evaluation of relevant IFRS standards, including identifying the differences between IFRS and the Company's current accounting policies, in order to prioritize the key areas that will be more significantly impacted by IFRS and to determine the options permitted under IFRS.

In the third phase, expected to commence in the fourth quarter of fiscal 2011, the Company will implement the accounting changes and any required modification to internal procedures, systems and controls so they are in place and operating effectively for the first fiscal year under IFRS.

IFRS uses a conceptual framework similar to Canadian GAAP, but there are significant differences in recognition, measurement, and disclosures. As IFRS is expected to change prior to 2011, the impact of IFRS on the Company's consolidated financial statements is not reasonably determinable at this time.

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.

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 May 20, 2010 the Company had the following common shares and stock options outstanding:

Common Shares	67,079,492
Share Purchase Warrants	13,000,000
Stock Options	5,415,000

There are no shares held in escrow.

As of May 20, 2010, there was \$2,000,000 of two-year convertible debentures outstanding, convertible to common shares at rates of \$0.15 per share and \$0.25 per share.

“CAMERON WHITE”

Cameron White, President & Chief Executive Officer

“STEPHEN CHEIKES”

Steven Cheikes, Director