THUNDERBIRD ENERGY

YEAR ENDED JANUARY 31, 2011
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 26, 2011, and is for the years ended January 31, 2011 and 2010. 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 26, 2011.

### *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 continued to seek development financing for its Gordon Creek natural gas field and for its Weston County Wyoming light oil exploration project. The Company also continued to work closely with the US Department of Energy and the Southwest Regional Partnership during the approval and design phase of the previously announced 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, expect during the second quarter of the current year. The first major step in the project will be to conduct a 3D seismic survey of the Gordon Creek project, followed by a deep (3,650 meter) CO2 source well in the southern portion of the Gordon Creek lands to test the White Rim formation for its CO2 producing potential.

Production at Gordon Creek during the first three quarters of the fiscal year declined approximately 5% as compared to the comparable three quarters of the previous year. Temporary production difficulties encountered during the fourth quarter resulted in an overall production decline for the year of 9%.

Natural gas prices remained soft throughout the last year although did recover slightly from the previous year. Prices realized by the company during the year averaged US$3.50 compared to an average price of US$2.66 realized during the prior year. Economic indicators continue to suggest that the general economic activity is recovering leading to potential increased demand for gas, although US gas supplies continue to remain strong and drilling activity remains relatively flat. However, gas presently in storage has slipped below five year averages lending some price support. The Company entered into a fixed price forward sale of 200 Mcf/day for the period April 1, 2011 to October 31, 2011 at a price of $3.98 per Mcf.

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. The third and final phase of the REX pipeline was completed during 2009 and has substantially increased this take away capacity and lowered the average price differentials to the US$0.40 to US$0.50 range. The new Ruby pipeline which will increase take away capacity into Northern California is expected to be on stream in the 3rd quarter of this year. As a result the expectation is that these reduced differentials will remain in place for the foreseeable future, resulting in relatively higher gas pricing for the Rockies producers.

## 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, 2010** | **January, 31 2009** |
|---|---|---|---|
| Total revenues | 905,111 | 1,184,906 | 1,303,712 |
| Net loss | (2,905,003) | (2,029,517) | (2,693,700) |
| Basic and diluted loss per share | (0.04) | (0.03) | (0.06) |
| Total assets | 9,906,279 | 10,779,821 | 12,569,542 |
| Total long-term financial liabilities | 6,447,941 | 212,394 | 1,819,804 |

*The Company has not declared any cash dividends since inception*.

## RESULTS OF OPERATIONS

| | **Three Months Ended** | | | **Years Ended** | | |
|---|---|---|---|---|---|---|
| | **January 31, 2011** | **October 31, 2010** | **January 31, 2010** | **January 31, 2011** | **January 31, 2010** | **January, 31, 2009** |
| **Operating Income**[(1)] | **(30,618)** | **53,108** | 133,823 | **221,124** | 478,730 | 286,588 |
| General and administrative | (288,411) | (408,592) | (195,616) | (971,741) | (781,594) | (1,170,030) |
| Interest and debt service costs | (205,303) | (414,028) | (151,840) | (650,515) | (572,636) | (478,677) |
| Interest income | 617 | 167 | 403 | 1,216 | 9,876 | 4,445 |
| **Funds Flow From Operations**[(1)] | **(523,716)** | **(769,345)** | (213,230) | **(1,399,916)** | (865,624) | (1,357,674) |
| *Non-cash operating items:* | | | | | | |
| Accretion and debt service costs | (338,518) | (23,856) | (96,315) | (884,430) | (410,201) | (443,260) |
| Depletion, depreciation and accretion | (96,068) | (111,958) | (124,667) | (429,701) | (607,627) | (633,157) |
| Stock-based compensation | (52,316) | (55,995) | (141,640) | (220,301) | (206,774) | (175,807) |
| Unrealized foreign exchange gain (loss) | 5,400 | 5,136 | 180 | 29,345 | 60,709 | (83,802) |
| **Net loss for the period** | **(1,005,218)** | **(956,018)** | **(575,672)** | **(2,905,003)** | **(2,029,517)** | **(2,693,700)** |

(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 year ended January 31, 2011 the Company's gas sales volume averaged 610 Mcf/day as compared to 675 Mcf/d during the prior year, a decline of roughly 9.6%. During the three months ended January 31, 2011 the Company's gas sales volume averaged 507 Mcf/d as compared to average daily gas sales volumes of 693 Mcf/d during the comparable quarter of the prior year. Over 50% of this decline can be attributed to one of the Company's wells that encountered production difficulties during the fourth quarter of the fiscal year. It is believed that the historical production levels can be restored in this well with the installation of a surface water pump planned for calendar 2011. The Company's oil sales volume for the same periods in fiscal 2011 averaged 3 bbls/d, down from 4bbls/d experienced in the respective three and twelve months periods ended January 31, 2010.

### *Production Summary*

The following table summarizes the production for the fourth quarter and year-end of fiscal 2011 and 2010:

| | Three months ended January 31, 2011 | 2010 | Year ended January 31, 2011 | 2010 |
|---|---|---|---|---|
| **Production:** | | | | |
| Natural gas (Mcf) | 46,646 | 63,761 | 222,686 | 249,488 |
| Oil (bbls) | 286 | 372 | 1,097 | 1,672 |
| Total (BOE) (6:1) | 8,067 | 10,999 | 38,211 | 43,253 |
| **Production split:** | | | | |
| Natural gas (%) | 96% | 97% | 97% | 96% |
| Oil (%) | 4% | 3% | 3% | 4% |

### *Average Realized Price*

The following table summarizes the average realized price for the fourth quarter and year-end of fiscal 2011 and 2010:

| | | Three months ended January 31, 2011 | 2010 | Year ended January 31, 2011 | 2010 |
|---|---|---|---|---|---|
| **Exchange Rate** | *US$/Cdn$* | *0.9947* | *0.9484* | *0.9743* | *0.8877* |
| Natural gas (Mcf) | US$/Mcf | $ 3.33 | $ 3.55 | $ 3.50 | $ 2.66 |
| Oil (bbls) | US$/bbls | $ 84.08 | $ 69.07 | $ 74.45 | $ 55.91 |

### *Revenues, Royalties & Operating Costs*

| | Three Months Ended January 31, 2011 | October 31, 2010 | January 31, 2010 | Year Ended January 31, 2011 | January 31, 2010 |
|---|---|---|---|---|---|
| Revenues | $ 230,488 | $ 271,558 | $ 373,125 | $ 1,087,085 | $ 1,358,878 |
| Royalties expense | (36,610) | (39,681) | (54,875) | (181,974) | (173,972) |
| Operating costs | (224,494) | (178,769) | (184,427) | (683,987) | (706,176) |
| Operating Income[(1)] | $ (30,618) | $ 53,108 | $ 133,823 | $ 221,124 | $ 478,730 |

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

### *Revenues*

Fourth quarter revenues decreased 15% over the third quarter of 2011 and 38% compared to the fourth quarter of fiscal 2010. The decrease was primarily attributable to the temporary production difficulties referred to under the heading “Operating Income Items – Sales Volumes” above. Revenues (reported in Canadian dollars) were also negatively impacted by a decline in the value of the US dollar during the year and the quarter. In addition, the Company’s third party water disposal revenues declined during the year. These factors collectively combined to reduce the company’s revenues for the year by 20% as compared to fiscal 2010.

### *Royalties*

Royalties as a percentage of petroleum and natural gas sales were 20% during the fourth quarter, consistent with the third quarter. Royalties as a percentage of petroleum and natural gas sales were 21% for fiscal 2011 comparable with 21% in the prior fiscal year.

### *Operating costs*

Operating expenses include all normal operating costs as well as workover costs for both the Gordon Creek and the Rush County projects. Normal operating costs declined approximately 3% during the year. A portion of this decline was related to the decline in the US dollar as well as a decline in production. However, reported fourth quarter costs increased 26% and 22% over the third quarter and fourth quarter of fiscal 2010 respectively, due entirely to a $72,000 allowance for a doubtful account that was recorded in the fourth quarter and charged to operating costs.

## 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, 2011 | October 31, 2010 | January 31, 2010 | January 31, 2011 | January 31, 2010 |
| Reported amount | $ 288,412 | $ 408,592 | $ 195,616 | $ 971,741 | $ 781,594 |
| G&A ($/boe) | $ 35.75 | $ 41.89 | $ 17.79 | $ 25.43 | $ 18.07 |

G&A expenses decreased 29% in the fourth quarter of fiscal 2011 as compared to the preceding quarter. The higher G&A expenses incurred in the third quarter were largely due to additional legal fees incurred on the debenture financing which closed at the end of the third quarter.

G&A expenses for the three months and year ended January 31, 2011 were 47% and 24% more than the corresponding periods in fiscal 2010, due to increased filing fees from the 2011 debenture financing, in addition to higher accrued professional fees pertaining to year-end services.

### *Interest, accretion and debt service costs*

Interest charges for the year include interest incurred on the credit facility with Macquarie Bank of approximately $216,079 (2010 - $274,012) interest paid or accrued on short term debt and promissory notes of approximately $75,627 (2010 - $59,606) and interest paid on convertible debentures of approximately $195,084 (2010 - $239,018) and interest paid on debentures of approximately $325,877 (2010 – nil). Accretion costs of approximately $75,608 (2010 - $79,562) relate to the accretion on the convertible debentures. Debt service costs of approximately $653,807 (2010 - $330,639) relate to the imputed fair value of warrants issued.

| | Three Months Ended | | | Year Ended | |
|---|---|---|---|---|---|
| | **January 31, 2011** | **October 31, 2010** | **January 31, 2010** | **January 31, 2011** | **January 31, 2010** |
| Reported amount | $ 543,821 | $ 437,884 | $ 248,155 | $ 1,534,945 | $ 982,837 |
| Expense per sales volume ($/boe) | $ 67.41 | $ 44.89 | $ 22.56 | $ 40.17 | $ 22.72 |

Interest, accretion and debt service costs increase significantly in the fourth quarter of the current year due to debt service costs recorded on the fair value of warrants issued pertaining to the debenture and equity financing completed during the year.

### *Depletion, depreciation and accretion*

| | Three Months Ended | | | Year Ended | |
|---|---|---|---|---|---|
| | **January 31, 2011** | **October 31, 2010** | **January 31, 2010** | **January 31, 2011** | **January 31, 2010** |
| Reported amount | $ 96,068 | $ 111,958 | $ 124,667 | $ 429,701 | $ 607,627 |
| Expense per sales volume ($/Boe) | $ 11.91 | $ 11.48 | $ 11.33 | $ 11.25 | $ 14.05 |

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, 2011 in accordance with NI 51-101.

### *Unrealized foreign exchange (gain) loss*

At the end of the fourth quarter the Company had $5,400 in unrealized foreign exchange gain, as the Canadian dollar strengthened over the US dollar over the third quarter. The Company had unrealized foreign exchange gain of approximately $29,345 (2010 - $60,709) for fiscal 2011. This gain pertains to the translation of short-term debt and promissory notes denominated in U.S. currency. The unrealized foreign exchange gain is due to a stronger Canadian dollar at January 31, 2011 than at January 31, 2010.

### *Stock-based compensation*

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

| | 2011 | 2010 |
|---|---|---|
| Weighted average fair value per share | $ 0.15 | $ 0.20 |
| Dividend yield | 0% | 0% |
| Interest rate | 1.94% | 2.28% |
| Expected life | 3 years | 4.45 years |
| Volatility | 154.64% | 144% |

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

| Fiscal | | Amount |
|---|---|---|
| 2012 | $ | 21,527 |
| Thereafter | | - |
| | $ | 21,527 |

## 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 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.

Unconventional natural gas reserves and production have steadily increased in the United States over the past few years as a result of new horizontal drilling and “multi-frac” stimulation technologies that have allowed the commercialization of several large shale gas formations. This has caused downward pressure on gas prices. This downward pressure has been mitigated somewhat by the decrease in conventional gas drilling as well as increasing overall demand coincident with the ongoing economic recovery. Long term, there is an ongoing push to switch to natural gas for energy generation and transportation as a cleaner burning and potentially less expensive alternative to coal and oil, however the timing and extent of this shift is uncertain.

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, 2011 the Company had no such instruments in place. Effective April 1 to October 31, 2011 the Company has entered into a fixed price contract in place to sell 200 Mcf per day at $3.98 per Mcf.

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, joint venture and equity financing. There is no assurance that 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 debentures and 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, 2011, the Company's additions to its oil and gas properties totalled $281,044 (2010 -$333,951).

At January 31, 2011, the Company had cash of $62,810 (2010 - $24,783) and a working capital deficiency of $1,662,298 (2010 - $7,977,884). The working capital deficiency includes a current liability of $2,171,310 (2010 - $8,586,820) which consists of accounts payable, amounts due to related parties, short-term debt and the convertible debentures. The working capital deficiency 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, 2011. The Company has no lines of credit or other sources of financing which have been arranged at this time, other than those listed below.

### *Long Term Debt*

During the year, the Company issued three year, secured, natural gas linked debentures totaling $7,500,000. 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. 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.

### *Convertible debentures*

As at January 31, 2011, convertible debentures with the face value of $515,000 issued in December of 2008 at 12% interest, paid quarterly, were outstanding and due on demand. As of May 26, 2011, $290,000 principal amount of these debentures remained outstanding. 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 $0.15 per share.

## 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 $93,375 in consulting fees for the year ($22,050 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 $17,253 by way of a partial reimbursement of rent, supplies and computer expenses during the year ($4,742 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 $50,000 in consulting fees for the year ($5,000 in the fourth quarter).

Thunderbird Films Inc, a company that shares common directors with the Company, was accrued $89,120 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 $nil (2010 - U.S. $150,675 (Cdn $161,358)) and $88,499 (2010 - $60,318). The loan carries a 12% interest rate and is payable on demand. Also included is $211,174 (2010 - $627,384) due to directors and companies with common directors.

## QUARTERLY FINANCIAL INFORMATION *(unaudited)*

| **Income Statement:** | **Q4 2011** | **Q3 2011** | **Q2 2011** | **Q1 2011** | **Q4 2010** | **Q3 2010** | **Q2 2010** | **Q1 2010** |
|---|---|---|---|---|---|---|---|---|
| Net Revenues after Royalties | 193,876 | 231,878 | 223,446 | 255,911 | 318,250 | 270,334 | 335,972 | 260,350 |
| Expenses | 1,199,094 | 1,187,896 | 764,114 | 666,571 | 893,922 | 771,464 | 836,005 | 713,032 |
| Net loss for the period | (1,005,218) | (956,018) | (540,668) | (410,660) | (575,672) | (501,130) | (500,033) | (452,682) |
| Basic and diluted loss per share | (0.014) | (0.014) | (0.008) | (0.006) | (0.009) | (0.007) | (0.008) | (0.007) |
| Weighted average number of shares outstanding (thousands) | 71,926 | 69,864 | 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, 2011. 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, 2011.

### *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, 2011.

### *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 $363,044 (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 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. The standard is effective for business combinations occurring after January 1, 2011. The adoption of this standard has no material impact on the Company’s financial statements.

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. The adoption of this standard has no material impact on the Company’s financial statements.

The above CICA Handbook sections are converged with International Financial Reporting Standards (“IFRS”). The Company will be required to report its results in accordance with IFRS beginning February 1, 2011.

## SIGNIFICANT ACCOUNTING PROUNOUNCEMENTS

## 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 changeover to IFRS represents a change 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 operations.

In July 2009, the International Accounting Standards Board issued Additional Exemptions for First-time Adopters (Amendments to IFRS-1) which gives the option to companies using the full cost method of accounting to carry forward the amount determined under Canadian GAAP as the deemed cost under IFRS. This exemption will significantly reduce property, plant and equipment adjustments which would have resulted from the retroactive adoption of IFRS.

The Company is following a three-phase transition plan: initial review and assessment, in-depth analysis, and implementation. The Company commenced the process of transitioning its financial statements from current Canadian GAAP to IFRS in 2010 and now is in the third stage of implementation.

## 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 26, 2011 the Company had the following common shares and stock options outstanding:

| | |
|---|---|
| Common Shares | 74,439,485 |
| Share Purchase Warrants | 13,000,000 |
| Stock Options | 4,115,000 |

There are no shares held in escrow.

As of May 26, 2011, there was $290,000 principal amount of two-year convertible debentures outstanding, convertible to common shares at a rate of $0.15 per share.

***"CAMERON WHITE"*** ***"STEPHEN CHEIKES"***

Cameron White, Chief Executive Officer Steven Cheikes, Director