THUNDERBIRD
ENERGY

PERIOD ENDED JULY 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 September 27, 2011, and is for the three and six months ended July 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 International Financial Reporting Standards, 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 September 27, 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% interest in a non-producing oil project in Weston County, Wyoming.

Changes in Accounting Policies

On February 1, 2011, the Company adopted International Financial Reporting Standards ("IFRS") for financial reporting purposes, using transition date of February 1, 2010. The unaudited consolidated financial statements for the three and six months ended July 31, 2011, including required comparative information, have been prepared in accordance with IFRS 1 – *First-Time Adoption of International Financial Reporting Standards*, and with International Accounting Standard ("IAS") 32 – *Interim Financial Reporting*, as issued by the International Accounting Standards Board ("IASB"). Previously, the Company prepared its Interim and Annual Consolidated Financial Statements in accordance with Canadian generally accepted accounting principles ("previous GAAP"). Unless otherwise noted, fiscal 2011 comparative information has been prepared in accordance with IFRS. The adoption of IFRS has not had an impact on the Company's operation, strategic decisions and funds flow from operations.

HIGHLIGHTS AND OUTLOOK

During the quarter, the Company entered into a US$25 million commodity stream production payment agreement with Sandstorm Metals & Energy Ltd. ("Sandstorm") whereby Sandstorm will advance $25 million to the Company in 2011 and 2012 in exchange for the right to purchase 35% of the Company's Gordon Creek natural gas production at a price of $1.00 per Mcf plus 20% of the amount by which the Gordon Creek field gate price exceeds $4.00. The Company has agreed to drill 50 wells and workover 5 standing wells during 2011 and 2012, and has also provided Sandstorm with minimum annual cash flow guarantees until 2018. Subsequent to the end of the quarter the Company closed the agreement with Sandstorm and received the first tranche payment of US$15 million. The second tranche payment is scheduled to be paid in the second quarter of calendar 2012.

During the quarter the Company also received US Department of Energy approval to commence operations at the previously announced Gordon Creek Carbon Sequestration Phase III: Deep Saline Sequestration Deployment. 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 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) CO_2 source well in the southern portion of the Gordon Creek lands to test the White Rim formation for its CO_2 producing potential.

Natural gas prices remained relatively soft throughout the quarter although, somewhat stronger than the prior year. Prices realized by the company during the quarter averaged US$3.94 compared to an average price of US$3.54 during the comparable quarter of 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 trended below five year averages for most of the current year 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, which 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 third quarter of this year. As a result the expectation is that these reduced differentials will remain in place for the foreseeable future, resulting in improved gas pricing for the Rockies producers.

RESULTS OF OPERATIONS

	Three Months Ended			Six Months Ended	
	July 31, 2011	**April 30, 2011**	**July 31, 2010**	**July 31, 2011**	**July 31, 2010**
Operating Income[1]	**54,225**	**57,294**	**81,686**	**111,519**	**198,634**
General and administrative	(276,050)	(153,696)	(199,172)	(429,746)	(345,300)
Interest and debt service costs	(224,408)	(168,122)	(153,963)	(392,530)	(303,792)
Interest income	171	110	219	281	432
Funds Flow From Operations [1]	**(446,062)**	**(264,414)**	**(271,230)**	**(710,476)**	**(450,026)**
Non-cash operating items:					
Accretion and debt service costs	(193,834)	(173,733)	(87,942)	(367,567)	(178,885)
Depletion and depreciation	(51,715)	(43,668)	(54,738)	(95,383)	(108,941)
Accretion on decommissioning liablities	(2,963)	(2,954)	(3,071)	(5,917)	(6,069)
Share based compensation	(45,013)	(14,689)	(68,933)	(59,702)	(153,185)
Unrealized foreign exchange gain	20,250	15,314	(7,042)	35,564	18,809
Net loss for the period	**(719,337)**	**(484,144)**	**(492,956)**	**(1,203,481)**	**(878,297)**

[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 July 31, 2011 the Company's sales volume averaged 563 mcf/d and 3 bbls/d respectively. This compared to average daily sales volumes of 479 mcf/d and 3 bbls/d experienced in the three months period ended April 30, 2011 and 648 mcf/d and 2bbls/day in the three months ended July 31, 2010. The lower production volumes during the quarter ended April 30, 2011 was largely attributable to production difficulties encountered at one of the company's wells. Temporary measures were implemented subsequent to April 30, 2011 that partially restored production rates in the current quarter. The well is scheduled for a work over operation in the third quarter of fiscal 2012 which is anticipated to restore the well to historical production rates.

Production Summary

The following table summarizes the production for the second quarter of fiscal 2012 and fiscal 2011:

	Three months ended July 31, 2011	Three months ended July 31, 2010	Six months ended July 31, 2011	Six months ended July 31, 2010
Production:				
Natural gas (mcf)	51,828	59,572	94,424	119,410
Oil (bbls)	245	147	539	489
Total (BOE) (6:1)	8,883	10,076	16,276	20,391
Production split:				
Natural gas (%)	97%	99%	97%	98%
Oil (%)	3%	1%	3%	2%

Average Realized Price

The following table summarizes the average realized price for the second quarter of fiscal 2012 and fiscal 2011:

		Three months ended July 31, 2011	Three months ended July 31, 2010	Six months ended July 31, 2011	Six months ended July 31, 2010
Exchange Rate	*US$/Cdn$*	*1.0341*	*0.9589*	*1.0302*	*0.9672*
Natural gas (mcf)	*US$/Mcf*	*$ 3.94*	*$ 3.54*	*$ 3.74*	*$ 3.65*
Oil (bbls)	*US$/bbls*	*$ 90.49*	*$ 66.70*	*$ 90.35*	*$ 71.69*

Revenues, Royalties & Operating Costs

	Three Months Ended July 31, 2011	Three Months Ended April 30, 2011	Three Months Ended July 31, 2010	Six Months Ended July 31, 2011	Six Months Ended July 31, 2010
Revenues	$ 260,423	$ 207,557	$ 280,566	$ 467,980	$ 585,040
Royalties	55,484	34,057	57,120	89,541	105,683
Operating costs	150,714	116,206	141,760	266,920	280,723
Operating Income(1)	$ 54,225	$ 57,294	$ 81,686	$ 111,519	$ 198,634

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

Revenues

Second quarter revenues increased 25% over the first quarter of 2012. The increase was due to both an increase in prices of natural gas and higher levels of production. Production levels were higher than the first quarter primarily attributed to the temporary production difficulties in the first quarter referred to under the heading "Operating Income Items – Sales Volumes" above. Revenues decreased 7% over the second quarter of fiscal 2011. This decrease was due to lower production as discussed above, but offset by the higher prices in fiscal 2012 than 2011.

Revenues for the six months ended July 21, 2011 decreased 20% over the corresponding period in fiscal 2011. This was due mainly to the lower production in the first quarter as discussed above. In addition, revenues (reported in Canadian dollars) were also negatively impacted by a decline in the value of the US dollar during the quarter.

Royalties

Royalties as a percentage of petroleum and natural gas sales were 25% during the second quarter, consistent with the second quarter of fiscal 2011. Royalties as a percentage of petroleum and natural gas sales were 5% higher than the first quarter of fiscal 2012 as the Utah State annual required minimum royalty charge period ended during the quarter and therefore the remaining minimum royalties was expensed consistent with 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 workover costs for both the Gordon Creek and the Rush County projects. Second quarter costs increased 30% over the first quarter of the year and 6% over the corresponding period in fiscal 2011 due primarily to workover costs incurred on the Rush County project.

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			Six Months Ended	
	July 31, 2011	April 30, 2011	July 31, 2010	July 31, 2011	July 31, 2010
Reported amount	$ 276,050	$ 153,696	$ 199,172	$ 429,746	$ 345,300
G&A ($/boe)	$ 37.34	$ 20.79	$ 19.77	$ 26.40	$ 16.93

G&A expenses increased 80% in the second quarter of fiscal 2012 as compared to the immediately preceding quarter and increased 39% over the second quarter of fiscal 2011. The higher G&A expenses incurred in the second quarter of fiscal 2012 were largely due to additional professional fees incurred for work relating to the closing of the US$25 million commodity stream production payment agreement with Sandstorm Metals & Energy Ltd.

G&A expenses for the six months ended July 31, 2011 reflected a 24% increase over the six months ended July 31, 2010 primarily due to increased consulting fees and salaries in the first quarter of the current year as well as an increase in professional fees attributable to the commodity stream production payment agreement with Sandstorm Metals & Energy Ltd. closed in the third quarter of fiscal 2012.

Interest, accretion and debt service costs

Interest charges for the quarter interest paid or accrued on short term debt and promissory notes of approximately $71,111 (Q2 Fiscal 2011 - $23,022) and interest paid on convertible debentures of $4,166 (Q2 Fiscal 2011 - $60,493) and interest paid on debentures of approximately $339,215 (Q2 Fiscal 2011 – nil). Debt service costs of $3,750 (Q2 Fiscal 2011 - $65,065) relate to the imputed fair value of warrants issued and commissions on debentures issued.

	Three Months Ended						Six Months Ended			
		July 31, 2011		April 30, 2011		July 31, 2010		July 31, 2011		July 31, 2010
Reported amount	$	418,242	$	341,855	$	241,905	$	760,097	$	482,677
Expense per sales volume ($/boe)	$	56.57	$	46.24	$	24.01	$	46.70	$	23.67

The 22% increase in interest, accretion and debt service costs for the three months ended July 31, 2011 over the first quarter of fiscal 2012 was primarily due to interest paid on short term debt which increased in the second quarter due to a short-term US$2 million loan. The 73% increase in costs over the corresponding quarter in fiscal 2011 and 57% over the corresponding six months period ending July 31, 2011 in fiscal 2011 was due to both increase in interest on short term debt in the current quarter as well as an increase in interest pertaining to the debentures issued in the third quarter of fiscal 2011.

Depletion and depreciation

	Three Months Ended						Six Months Ended			
		July 31, 2011		April 30, 2011		July 31, 2010		July 31, 2011		July 31, 2010
Reported amount	$	51,715	$	43,668	$	54,738	$	95,383	$	108,941
Expense per sales volume ($/boe)	$	6.99	$	5.91	$	5.43	$	5.86	$	5.34

Depletion and depreciation is primarily associated with the Gordon Creek. The net carrying value of the development or production assets is depleted using the unit-of-production method by reference to the ratio of production in the period over the related proven and probable reserves while also taking into account estimated future development costs necessary to bring those reserves into production. Changes in depletion and depreciation expense are consistent with the changes in production over previous quarters.

Unrealized foreign exchange gain

At the end of the second quarter of fiscal 2012 the Company had unrealized foreign exchange gain of $35,564. 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 July 31, 2011 than at January 31, 2011.

Stock-based compensation

In accordance with IFRS 2, the fair value of each option granted during the period is estimated on the date of the grant using the Black-Scholes option pricing model with the following weighted average assumptions:

	July 31, 2011	January 31, 2011
Fair value per share	$ 0.15	$ 0.15
Dividend yield	0%	0%
Interest rate	2.39%	1.94%
Expected life	3 years	3 years
Forfeiture Rate	17.13%	9.88%
Volatility	135%	155%

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. 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 quarter, the Company entered into a US$25 million commodity stream production payment agreement with Sandstorm Metals & Energy Ltd. (the "Sandstorm Agreement") whereby Sandstorm will advance $25 million to the Company in 2011 and 2012 in exchange for the right to purchase 35% of the Company's Gordon Creek natural gas production at a price of $1.00 per Mcf plus 20% of the amount by which the Gordon Creek field gate price exceeds $4.00. The Company has agreed to drill 15 wells and workover 5 standing wells during calendar 2011 and to drill and additional 35 wells in calendar 2012, of which and has also provided Sandstorm with minimum annual cash flow guarantees until 2018.

At July 31, 2011, the Company had cash of $899,378 (January 31, 2011 - $62,810) and a working capital deficiency of $1,726,498 (January 31, 2011 - $1,662,298). The working capital deficiency includes a current liability of $3,035,568 (January 31, 2011 - $2,171,310) which consists of accounts payable, amounts due to related parties, short-term debt and the convertible debentures. The working capital deficiency as at July 31, 2011 contributes to factors which raise substantial doubt about the Company's ability to continue as a going concern, as discussed in Note 2 of the financial statements. Subsequent to the end of the quarter the Company closed the above referenced Sandstorm Agreement and received the first tranche payment of US$15 million. The second tranche payment is scheduled to be paid in the second quarter of calendar 2012.

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.

With the exception of the obligations to drill 50 wells and complete 5 workover operations pursuant to the Sandstorm Agreement outlined above, the Company had no commitments for capital expenditures as of July 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

In fiscal 2011, the Company issued three year, secured, natural gas linked debentures totaling $7,500,000. In the first and second quarter of fiscal 2012, the Company issued an additional $342,000 of these debentures. The debentures bear interest at a base rate of 15% per annum with an adjustment provision whereby a 1% interest premium 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 15,684,000 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

During the second quarter the Company repaid the outstanding convertible debentures with the face value of $290,000 issued in December of 2008.

TRANSACTIONS WITH RELATED PARTIES

Koele Capital Corp. ("Koele") of which the 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 President and COO is a shareholder, was paid $32,400 in consulting fees for the quarter. The Company has an ongoing contractual arrangement with Westrich to pay consulting fees of $10,800 per month. Westrich was also pad $6,970 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.

Thunderbird Films Inc, a company that shares common directors with the Company, was accrued $32,043 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 unsecured short-term loans payable and accrued interest to directors of the Company for $262,443 (January 31, 2011 - $88,500). The loans carry a 12% interest rate and are payable on demand. Also included is $112,081 (January 31, 2011 - $211,174) due to officers and directors and companies with common directors. Included in the long-term debt is $2,629,000 held by related parties.

QUARTERLY FINANCIAL INFORMATION *(unaudited)*

							Previous GAAP[(1)]	
Income Statement:	**Q2 2012**	**Q1 2012**	**Q4 2011**	**Q3 2011**	**Q2 2011**	**Q1 2011**	**Q4 2010**	**Q3 2010**
Net Revenues after Royalties	204,939	173,500	193,876	231,878	223,446	255,911	318,250	270,334
Expenses	924,276	657,644	1,129,104	1,113,340	716,402	641,252	893,922	771,464
Net loss for the period	(719,337)	(484,144)	(935,228)	(881,462)	(492,956)	(385,341)	(575,672)	(501,130)
Basic and diluted loss per share	(0.010)	(0.007)	(0.013)	(0.013)	(0.008)	(0.006)	(0.009)	(0.007)
Weighted average number of shares outstanding (thousands)	75,297	73,174	71,926	69,864	67,079	67,079	67,079	67,079

(1) As the Company's transition date was February 1, 2010, fiscal 2010 comparatives figures have not been restated

CRITICAL ACCOUNTING ESTIMATES

The preparation of the interim consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and disclosure of contingent assets and liabilities at the date of the financial statements and for the periods presented. Such estimates primarily related to unsettled transactions and events as at the date of the interim consolidated financial statements. Actual results may differ from those estimates. Significant estimates and judgments made by Management in the preparation of these interim consolidated financial statements are outlined below.

Fair value of oil and gas properties, depletion and depreciation and amounts used in impairment calculations are based on estimates of oil and natural gas reserves, future prices and future costs required to develop those reserves. By nature, estimates of reserves and the related future cash flows are subject to measurement uncertainty, and the impact of the differences between actual and estimated amounts on the consolidated financial statements of future periods could be material.

Petroleum and natural gas properties, exploration and evaluation assets and other corporate assets are aggregated into cash-generating-units ("CGUs") based on their ability to generate largely independent cash flows and are used for impairment testing. The determination of the Company's CGUs is subject to management's judgment.

The decision to transfer exploration and evaluation assts to property and equipment is based on management's determination of an area's technical feasibility and commercial viability based on proved and probable reserves.

Amounts recorded in decommissioning liabilities and the related accretion expense require the use of estimates including timing of asset retirements, site remediation, discount rate, inflation rate and related cash flows. Provisions are recognized in the period when it becomes probable that there will be a future cash outflow.

Compensation costs accrued for share-based compensation plans are subject to the estimated fair values, forfeiture rates.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change and interpretation. Deferred tax assets are assessed by management at the end of the reporting period to determine the likelihood that they will be realized from future taxable earnings.

ADOPTION OF INTERNATIONAL FINANCIAL REPORTING STANDARDS ("IFRS")

The interim consolidated financial statements for the three and six months ended July 31, 2011, including required comparative information, have been prepared in accordance with IFRS applicable to the preparation of interim financial statements, including IAS 34 (Interim Financial Reporting) and IFRS 1 (First-time Adoption of IFRS). Previously, the Company prepared its Interim and Annual Consolidated Financial Statements in accordance with Canadian GAAP. The adoption of IFRS has not had any impact on the Company's operations, strategic decisions and funds flow from operations.

The Company's IFRS accounting policies are provided in Note 4 to the Interim unaudited consolidated financial statements for the three and six months ended July 31, 2011 and, in addition Note 17 presents reconciliations between the Company's 2011 previous GAAP results and the 2011 IFRS results. The reconciliations include the Consolidated Balance Sheets as at February 1, 2010, July 31, 2010 and January 31, 2011, and the Consolidated Statements of Comprehensive Loss for the three and six months ended July 31, 2010 and for the year ended January 31, 2011.

Accounting Policies Changes

The following discussion explains the significant differences between the Company's previous Canadian GAAP accounting policies and those applied under IFRS. IFRS policies have been retrospectively and consistently applied except where specific IFRS 1 optional and mandatory exemptions permitted an alternative treatment upon transition to IFRS for first-time adopters.

Exploration and evaluation assets

Exploration and evaluation assets as February 1, 2010 were deemed to be US$999,977 (Cdn $1,070,876), representing the unproved properties balance under previous GAAP. This balance included US$16,647 (Cdn $17,827) in previously capitalized legal costs incurred in setting up the acquisition of property. As these expenditures were incurred prior to obtaining legal rights to explore the property, under IFRS the Company is required to expenses pre-license costs. Therefore at February 1, 2010, the Company reclassified US$983,330 (Cdn $1,053,049) from property and equipment to exploration and evaluation assets and US$16,647 (Cdn $17,827) to the deficit as at February 1, 2010.

Under previous GAAP, exploration and evaluation expenditures were capitalized as property and equipment in accordance with the CICA's full cost accounting guidelines. Under IFRS, the Company capitalizes these costs initially as exploration and evaluation assets. When an area is determined to be technically feasible and commercially viable, the accumulated costs are transferred to property and equipment. When an area is determined not to be technically feasible and commercially viable or the Company decides not to continue with its activity, the unrecoverable costs are charged to net earnings as exploration and evaluation expense.

Decommissioning liability

Under previous GAAP, the Company's asset retirement obligation was discounted using and average credit-adjusted risk free rate. Under IFRS, the Company discounted its decommissioning liability using an average risk free rate. As at February 1, 2010, the differences resulted in an increase in the decommissioning liability by US$93,187 (Cdn $99,793), with a corresponding decrease to accumulated deficit.

Depreciation and depletion

Under previous GAAP, development costs were depleted using unit-of-production method based on proved reserves for each country cost centre. Under IFRS, development costs are depleted using the unit-of-production method based on proved and probable reserves at the established CGU. This resulted in a $203,176 decrease to the Company's depreciation and depletion expense for the year ended January 31, 2011.

Impairment

Under IFRS, the Company is required to test for impairment at the CGU level. Upon review of impairment on the date of transition, February 1, 2010, the Company determined that one asset was impaired resulting in a charge against the accumulated deficit in the amount of US$1,002,775 (Cdn $1,073,872).

Change in estimates

Under IFRS the depreciation method applied to an asset must be reviewed at least at each financial year-end and any significant change in the expected pattern of consumption should be accounted for as a change in an accounting estimate. Therefore upon transition to IFRS the Company reviewed its depreciation method and determined that a straight line depreciation policy for corporate and production assets was more appropriate. The change in estimate resulted in a decrease to Property and Equipment of $8,875 with a corresponding increase to accumulated deficit.

Share-Based Compensation

To conform with IFRS, as at the transition date the Company revalued its contributed surplus arising from share-based compensation to recognize the impact of estimating forfeitures and changing to graded vesting required under whereby each traunche is individually valued with greater costs recognized up front instead of equally over the vesting period, as was the case under previous GAAP.

Recent Pronouncements Issued

All accounting standards effective for periods beginning on or after February 1, 2011 have been adopted as part of the transition to IFRS. The following new IFRS pronouncements have been issued but are not yet effective and may have an impact on the Company:

As of February 1, 2013, the Company will be required to adopt IFRS 9 - *Financial Instruments*, which is the first step in the process to replace IAS 39 – *Financial Instruments: Recognition and Measurement*. IFRS 9 replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value. The adoption of this standard should not have a material impact on the Company's consolidated financial statements.

In May 2011, the IASB issued the following standards which have not yet been adopted by the Company:
IFRS 10 – *Consolidation,* IFRS 11 – *Joint Arrangements,* IFRS 12 – *Disclosure of Interests in Other Entities,* IFRS 13 – *Fair Value Measurement,* IAS 27 – *Separate Financial Statements* and IAS 28 *Investments in Associates and Joint Ventures.* Each of the new standards is effective for annual periods beginning on or after January 1, 2013 with early adoption permitted. The Company has yet to assess the full impact of these new and amended standards.

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" which do not have any standardized meaning under IFRS and Canadian GAAP and may not be comparable to similar measures presented by other companies.

"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 IFRS or Canadian 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 IFRS or Canadian GAAP, as set forth above, or other measures of financial performance calculated in accordance with reporting standards.

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 September 27, 2011 the Company had the following common shares and stock options outstanding:

Common Shares	78,987,215
Share Purchase Warrants	35,282,584
Stock Options	4,815,000

There are no shares held in escrow.

"CAMERON WHITE"
Cameron White, Chief Executive Officer

"STEPHEN CHEIKES"
Steven Cheikes, Director