DEJOUR ENERGY INC.
RESOURCEFUL. ENTERPRISING.

(formerly operating as Dejour Enterprises Ltd.)

MANAGEMENT DISCUSSION AND ANALYSIS

For the Three Months Ended March 31, 2012

Date of Report: May 10, 2012

The following is a discussion of the consolidated operating results and financial position of Dejour Energy Inc. (the "Company" or "Dejour"), including all its wholly-owned subsidiaries. It should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2011 and the condensed interim unaudited consolidated financial statements for the three months ended March 31, 2012. On March 9, 2011, the Company changed its name from Dejour Enterprises Ltd. to Dejour Energy Inc.

Effective January 1, 2011, the Company adopted International Financial Reporting Standards ("IFRS") and the following disclosure, as well as its associated condensed interim consolidated financial statements, has been prepared in accordance with IFRS as issued by the International Accounting Standards Board.

All financial information in this MD&A is stated in Canadian dollars, the Company's presentation currency, unless otherwise noted. Some numbers in this MD&A have been rounded to the nearest thousand for discussion purposes. Certain forward-looking statements are discussed in this MD&A with respect to the Company's activities and future financial results. These are subject to risks and uncertainties that may cause projected results or events to differ materially from actual results or events. Readers should also read the Advisory section located at the end of this document, which provides information on Non-GAAP Measures, BOE Presentation and Forward-Looking Statements.

DEJOUR STRATEGY AND BUSINESS ENVIRONMENT

In 2012, deployment of capital will be primarily driven by commodity prices, thus the Company's near term focus is on the liquids rich gas developments in the Kokopelli Field and at South Rangely in the Piceance Basin of the U.S. Rockies. These two developments provide the most effective way to generate positive returns while positioning the Company for a broad uplift in value assuming gas prices recover from current lows. Though it is expected that the majority of the value of these two projects will come from the recovery of condensate and natural gas liquids ("NGL") produced in association with the natural gas, management of these development programs in a low natural gas price environment requires the Company to maintain a low debt to equity ratio, within the framework of minimal equity issuance. It is under these carefully structured investment guidelines that management has designed these two development programs with the expectation of enhancing long term shareholder value.

Subsequent to March 31, 2012, the Company received a binding commitment, subject to certain closing conditions, for a US$14 million debt facility that will be dedicated to funding the drilling program at Kokopelli Field in 2012.

In addition to the focus on the initial development projects in the Piceance Basin, in 2012, the Company will continue its work to optimize production and revenue from the Drake/Woodrush property in northeastern British Columbia. Through the first six months of 2011, essentially all of Dejour's capital investments were targeted to complete the development of the oil resources at Woodrush. During this time the Company successfully constructed new facilities and started up a waterflood of the Halfway "E" oil pool. Initial production response to the water injection was seen in June 2011 as the first of three producing wells in the field experienced an increase in oil production. In October 2011, the Company received approval of its application to the British Columbia Oil and Gas Commission to replace the current Daily Oil Allowable with a Voidage Replacement Scheme for the management of the waterflood. This approval allowed the Company to drill a third producer at the end of 2011 and to increase the water injection rate. As a result of this increased injection, an earlier production response is now expected in the two producing wells that have yet to respond to injection. The Company expects the full production response and peak production from Woodrush to occur in the second half of 2012.

COMPANY OVERVIEW

The Company's common shares trade on the Toronto Stock Exchange ("TSX") and the New York Stock Exchange AMEX ("NYSE-AMEX") under the symbol "DEJ". The Company ceased to trade on the TSX Venture Exchange ("TSX-V") and graduated to the TSX effective November 20, 2008.

The Company is in the business of acquiring, exploring and developing energy projects with a focus on oil and gas exploration in Canada and the United States. The Company holds approximately 110,000 net acres of oil and gas leases in the following regions:

- The Peace River Arch of northwestern British Columbia and northeastern Alberta, Canada.
- The Piceance, Paradox and Uinta Basins in the US Rocky Mountains.

Q1 2012 HIGHLIGHTS

In Q1 2012, the Company continued its focus on production optimization of the Drake/Woodrush property, while finalizing pre-drilling activities for the Kokopelli field development and drilling activities for the discovery well at South Rangely.

During the quarter, the Company achieved the following major objectives and also made significant progress on key strategic initiatives that resulted in:

1. Successfully completed and tied into production the 3rd oil well at the Company's Woodrush property.

2. Successfully formed a federal unit containing the leases adjacent to the lease on which the discovery (Federal 36-24A) well was drilled in 2011.

3. Completed construction of the first drilling pad in the Kokopelli Field.

SELECTED CONSOLIDATED FINANCIAL RESULTS

	Three months ended March 31,	
	2012	2011
	$	$
Gross Revenues	1,928,000	1,584,000
Operating Cash Flow [(1)]	(468,000)	(495,000)
Operating Loss [(1)]	(1,455,000)	(1,196,000)
EBITDA [(1)]	462,000	(1,305,000)
Adjusted EBITDA [(1)]	(348,000)	(242,000)
Net Loss	(354,000)	(2,079,000)
Net loss per share	(0.003)	(0.018)

[(1)] A non-GAAP measure, which is defined under the Non-GAAP Measures section of the MD&A.

OIL AND GAS EXPLORATION AND PRODUCTION

During 2012, the Company further refined its focus toward the conversion of resources into reserves. As a result, the Company's asset characterization has moved toward more tangible low risk near term development projects, moderate risk appraisal opportunities and moderate to high risk exploration potential.

DEJOUR'S BUSINESS

Canadian Activities

The Company's wholly-owned subsidiary, Dejour Energy (Alberta) Ltd. ("DEAL"), currently has interests in oil and gas properties in the Peace River Arch located principally in northeastern British Columbia.

DEAL holds approximately 11,000 net acres concentrated in the Peace River Arch.

Production and Development Projects

Woodrush/Drake

In October 2011, Dejour received approval to operate the waterflood on a voidage replacement basis and in December drilled a third production well while increasing total injection from 1200 BWPD to 2400 BWPD. The start-up and subsequent enhancement of the waterflood marked the end of major capital investments in Woodrush. Dejour will concentrate on optimizing injection and production in the waterflood, controlling cost and increasing margins as the oil production is gradually ramped up to its maximum level in the second half of 2012. Woodrush oil production in the first quarter of 2012 was increased by about 50% over the same period in 2011.

Effective December 31, 2011, the Company's reserve evaluation valued the before tax discounted net present value 10% (NPV10) of remaining proved reserves in the Woodrush oil pool at $19 million, with proved and probable reserves valued at $31 million net to Dejour's 75% working interest. The reserve evaluation was conducted by an independent firm, Deloitte & Touche LLP ("AJM Deloitte") of Calgary, Alberta.

US Activities

Kokopelli

The Company continued working with its partners to bring this project into production. Dejour has a 72% working interest in this 2,200 acre project which is ideally situated for exploitation of both the Williams Fork and Mancos shale bodies. The Williams Companies, Inc. and Bill Barrett Corporation are developing and producing on adjacent acreage to the east, west and north of the Company's acreage. Dejour USA has worked closely with important constituents including local citizenry and government, the Bureau of Land Management and the Colorado Division of Wildlife to develop a mutually acceptable development plan for this environmentally sensitive area. Construction of the first drilling pad commenced in the fourth quarter of 2011 with production expected to begin in the second half of 2012. According to National Instrument 51-101 standard in Canada, the reserve assessment for Dejour's leases at Kokopelli Field effective December 31, 2011, performed by Gustavson and Associates of Boulder, Colorado, showed the before tax discounted net present value 10% (NPV_{10}) of proved undeveloped reserves valued at $94 million and proven plus probable undeveloped reserves valued at $202 million.

South Rangely

In June 2011, the Company drilled and cased an evaluation well on this 5,500 gross acre (3,300 net acre) lease that is located just south of the Rangely field. The well was drilled and casing set on approximately 90 feet of gross Mancos "B" Sand and later successfully fractured and stimulated. The well flowed rich gas from the Mancos "B" Sand in commercial quantities. Analysis of the gas showed a higher NGL yield from the South Rangely discovery than that expected from our NGL development at the Kokopelli Field.

In March 2012, the formation of a federal exploration and production unit containing all of Dejour leasehold adjacent to the discovery well was approved by the Bureau of Land Management. The formation of this unit will allow the Company to continue to evaluate and develop its leases in South Rangely in a more efficient and environmentally sensitive manner than would have been possible if the development were pursed on individual leases.

West Grand Valley (Piceance Basin)

On the Company's West Grand Valley property, Dejour operates approximately 5180 gross acres with a 72% working interest in an area of active drilling by EnCana, Laramie Partners II and Axia. Success in developing the gas in the Lower Mancos (Niobrara) section has revitalized drilling interest in this area of the Piceance Basin. Included in the West Grand Valley property acreage is the 1400+ acre Roan Creek evaluation project. This project is located very close to and sandwiched between existing Williams Fork gas fields operated by Occidental and Chevron. While it is likely that the Williams Fork at Roan Creek will be somewhat thinner than is found to the east and west, Roan Creek has Mancos potential which can be tested via an exploratory tail to a Williams Fork appraisal well. During 2009, the various geologic and commercial studies conducted by the Company highlighted the potential at Roan Creek. As a result of those studies, the Company began to make plans for a single well drilling program. The permitting process is underway and drilling at Roan Creek will follow the first increment of drilling at Kokopelli.

Future Exploration and Evaluation

As a result of a reasonably comprehensive geologic and commercial study in 2009, Dejour has high graded two future development and appraisal projects including:

- Plateau (Piceance Basin) - This 3,014 acre (gross) project located south of Roan Creek has significant Williams Fork potential as evidenced by successful drilling by EnCana Corporation at acreage adjacent to the Company's holdings.
- North Rangely – This 18,000 acre (gross) project located north of the Rangely Field, is prospective for oil in the Lower Mancos (Niobrara), Dakota, Morrison and Phosphoria formations.

These potential developments will be deferred to at least 2013 as the current natural gas price has caused Dejour to delay the start of investments on its other leases in Colorado. Exploitation of these opportunities will in all likelihood proceed once developments at Kokopelli, South Rangely and Roan Creek have been advanced to the point that Company's cash flow and proved producing reserve base can support the additional development costs.

Additionally, Dejour holds approximately 100,000 net acres prospective for oil and gas exploitation in Colorado and Utah.

CAPITAL EXPENDITURES

Additions to property and equipment and exploration and evaluation assets:

	Three months ended March 31, 2012	2011
	$	$
Land acquisition and retention	22,445	36,825
Drilling and completion	474,283	1,383,668
Facility and pipelines	449,200	1,382,608
Capitalized general and administrative	218,917	99,818
Other assets	967	5,460
	1,165,812	2,908,379

DAILY PRODUCTION

	Three months ended March 31, 2012	2011
By Product		
Natural gas (mcf/d)	1,271	1,630
Oil and natural gas liquids (bbls/d)	204	136
Total (boe/d)	416	408

The decrease in natural gas production for the three months ended March 31, 2012 ("Q1 2012") was primarily because the Company placed less emphasis on maximizing the gas production with the low gas prices currently available. The increase in oil production for the current quarter was the result of successful implementation of the waterflood in the Halfway "E" Pool on the Company's Woodrush property.

SHARE CAPITAL

The following is a summary of share transactions for the three months ended March 31, 2012 and the year ended December 31, 2011:

	Common Shares # of Shares	$ Value of shares
Balance at December 31, 2010	110,180,545	**79,385,883**
- Issue of shares on exercise of warrants and options	4,751,841	1,574,401
- Warrant liability reallocated on exercise of warrants	-	738,548
- Contributed surplus reallocated on exercise of options	-	167,070
- Shares issued via private placements, net of issuance costs	11,010,000	2,693,813
- Subscriptions receivable on exercise of options	950,000	516,246
Balance at December 31, 2011	126,892,386	**85,075,961**
- Issue of shares on exercise of warrants and options	3,893,683	1,465,812
- Warrant liability reallocated on exercise of warrants	-	285,689
- Contributed surplus reallocated on exercise of options	-	198,103
Balance at March 31, 2012	130,786,069	**87,025,565**

As at May 10, 2012, the Company had 130,786,069 issued and outstanding common shares.

STOCK OPTIONS AND SHARE PURCHASE WARRANTS

The following table summarizes information about outstanding stock option transactions:

	Number of options	Weighted average exercise price
		$
Balance at January 1, 2011	**6,946,500**	**0.40**
Options granted	3,212,500	0.35
Options exercised	(1,150,000)	0.35
Options cancelled (forfeited)	(200,000)	0.40
Options expired	(305,000)	0.45
Balance at December 31, 2011	**8,504,000**	**0.39**
Options granted	1,775,001	0.45
Options exercised	(925,000)	0.38
Options cancelled (forfeited)	(25,000)	0.35
Balance at March 31, 2012	**9,329,001**	**0.40**

Details of the outstanding and exercisable stock options as at March 31, 2012 are as follows:

	Outstanding			Exercisable		
		Weighted average			Weighted average	
	Number of options	exercise price	contractual life (years)	Number of options	exercise price	contractual life (years)
		$			$	
$0.35	4,554,000	0.35	2.44	3,844,875	0.35	2.52
$0.45	4,775,001	0.45	2.22	3,356,631	0.45	2.25
	9,329,001	0.40	2.33	7,201,506	0.40	2.40

As at March 31, 2012, none of the outstanding and exercisable stock options were “in the money” (the exercise price was less than the market trading price).

The following table summarizes information about outstanding warrant transactions:

	Number of Warrants	Weighted average Exercise price
		$
Balance at January 1, 2011	**21,010,455**	**0.44**
Warrants granted	5,505,002	0.37
Warrants exercised	(4,551,841)	0.37
Warrants expired	(3,540,026)	0.48
Balance at December 31, 2011	**18,423,590**	**0.43**
Warrants exercised	(2,968,683)	0.37
Balance at March 31, 2012	**15,454,907**	**0.44**

Details of the outstanding and exercisable warrants as at March 31, 2012 are as follows:

	Outstanding			Exercisable		
	Number of warrants	Weighted average exercise price	Weighted average contractual life (years)	Number of warrants	Weighted average exercise price	Weighted average contractual life (years)
		$			$	
$0.40	3,642,856	0.40	3.63	3,642,856	0.40	3.63
$0.55	4,015,151	0.55	2.23	4,015,151	0.55	2.23
$0.40 US	7,700,000	0.40	2.73	7,700,000	0.40	2.73
$0.46 US	96,900	0.46	2.59	96,900	0.46	2.59
	15,454,907	0.44	2.81	15,454,907	0.44	2.81

SELECTED FINANCIAL HIGHLIGHTS

(See "Non-GAAP Measures" section below for explanations)

Operating Cash Flow

	Three months ended March 31, 2012	Three months ended March 31, 2011
	$	$
Cash flows from (used in) operating activities - GAAP	(1,119,000)	(833,000)
Less: changes in non-cash operating working capital	(651,000)	(338,000)
Operating Cash Flow - Non-GAAP	(468,000)	(495,000)

Operating Netback

	Three months ended March 31, 2012	Three months ended March 31, 2011
	$	$
Gross Revenues	1,928,000	1,584,000
Less: Royalties	(331,000)	(237,000)
Less: Operating and transportation	(952,000)	(507,000)
Operating Netback	645,000	840,000

Operating Loss

	Three months ended March 31, 2012	Three months ended March 31, 2011
	$	$
Net loss	(354,000)	(2,079,000)
Add back (losses) and deduct gains:		
Impairment losses	9,000	9,000
Change in fair value of warrant liability	(1,110,000)	874,000
Operating Loss	(1,455,000)	(1,196,000)

EBITDA

	Three months ended March 31, 2012	2011
	$	$
Net loss	(354,000)	(2,079,000)
Deferred tax recovery	-	(187,000)
Finance costs	125,000	243,000
Amortization, depletion and impairment losses	691,000	718,000
EBITDA	462,000	(1,305,000)

Adjusted EBITDA

	Three months ended March 31, 2012	2011
	$	$
EBITDA	462,000	(1,305,000)
Adjustments:		
Stock-based compensation	300,000	189,000
Change in fair value of warrant liability	(1,110,000)	874,000
Adjusted EBITDA	(348,000)	(242,000)

NON-GAAP MEASURES

Non-GAAP measures are commonly used in the oil and gas industry. Certain measures in this document do not have any standardized meaning as prescribed by IFRS and previous GAAP such as Operating Cash Flow, Operating Netback, Operating Loss, EBITDA and Adjusted EBITDA and therefore are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this document in order to provide shareholders and potential investors with additional information regarding our liquidity and our ability to generate funds to finance our operations.

Operating Cash Flow is a non-GAAP measure defined as cash flow from operating activities before changes in non-cash operating working capital items.

Operating Netback is a non-GAAP measure defined as gross revenues less royalties and operating and transportation expenses.

Operating Loss is a non-GAAP measure defined as net loss excluding non-cash items that management believes affects the comparability of operating results. These items may include, but are not limited to, unrealized financial instrument gain (loss), impairment losses and impairment reversals, gain (loss) on divestitures, and change in fair value of financial instruments.

EBITDA is a non-GAAP measure defined as net loss before income tax expense, finance costs, and amortization, depletion and impairment losses.

Adjusted EBITDA excludes certain items that management believes affects the comparability of operating results. Items excluded generally are non-cash items, one-time items or items whose timing or amount cannot be reasonably estimated.

RESULTS OF OPERATIONS – THREE MONTHS ENDED MARCH 31, 2012 AND 2011

Summary of Operational Highlights

Production and Netback Summary

	Three months ended March 31, 2012	2011
Production Volumes:		
Oil and natural gas liquids (bbls)	18,571	12,276
Gas (mcf)	115,660	146,667
Total (BOE)	37,848	36,720
Average Price Received:		
Oil and natural gas liquids ($/bbls)	88.46	82.51
Gas ($/mcf)	2.47	3.89
Total ($/BOE)	50.95	43.13
Royalties ($/BOE)	8.73	5.68
Operating and Transportation Expenses ($/BOE)	25.15	13.37
Netbacks ($/BOE)*	17.07	24.08

*See Non-GAAP Measures

Revenues

	Three months ended March 31, 2012	2011
	$	$
Gross Revenues	1,928,000	1,584,000
Royalties	(331,000)	(237,000)
Revenues, net of royalties	1,597,000	1,347,000
Financial instrument loss	(55,000)	(47,000)
Other income	8,000	8,000
Total revenue	1,550,000	1,308,000

For Q1 2012, the Company recorded $1,928,000 in oil and natural gas sales as compared to $1,584,000 in oil and natural gas sales for the three months ended March 31, 2011 (“Q1 2011”). The increase in gross revenues was due to higher oil production and realized oil prices in the current quarter. The decrease in natural gas production for the current quarter was because the Company placed less emphasis on maximizing the gas production with the low gas prices currently available.

Royalties for Q1 2012 increased to $331,000 from $237,000 for Q1 2011, due to higher oil production. Royalties are mainly driven by the varying production mix between oil and gas. Production for the current quarter had the highest relative % of oil and oil production which is subject to higher royalty rate compared to the royalty rate for natural gas.

The following table summarizes the commodity prices realized by the Company and the crude oil and natural gas benchmark prices for the three months ended March 31, 2012 and 2011:

	Three months ended December 31, 2012	2011
Dejour Realized Average Prices		
Natural gas ($/mcf)	$ 2.47	$ 3.89
Oil and natural gas liquids ($/bbl)	88.46	82.51
Total average price ($/boe)	$ 50.95	$ 43.13
Average Benchmark Prices		
Edmonton Par ($/bbl)	$ 92.81	$ 88.45
Natural gas - AECO-C Spot ($ per mcf)	$ 2.52	$ 3.77

For the current quarter, Dejour's average realized natural gas prices reflected lower benchmark prices compared to Q1 2011. Oil prices received for Q1 2012 increased to $88.46 per barrel ("bbl"), compared to $82.51 per bbl for Q1 2011. The increase was due to the gradual recovery of the global economy, leading to higher commodity prices.

Operating and Transportation Expenses

Operating and transportation expenses include all costs associated with the production of oil and natural gas and the transportation of oil and natural gas to the processing plants. The major components of operating expenses include labour, equipment maintenance, workovers, fuel and power. Operating and transportation expenses for Q1 2012 increased to $952,000 from $507,000 for Q1 2011. The increase was due to the increase in oil production, increased repairs and maintenance of oil wells and higher waterflood activity.

Finance Costs and Change in Fair Value of Warrant Liability

Finance costs for the current quarter decreased to $125,000 from $243,000 for the same quarter in prior year. The decrease was attributable to the line of credit facility obtained in September 2011 that bears a lower interest rate, compared to the bridge loan with a relatively higher interest rate.

The non-cash change in fair value of warrant liability for Q1 2012 was a gain of $1,110,000, compared to a loss of $874,000 for Q1 2011, primarily due to the decrease of the Company's share prices. The warrant liability relates to the fair value of certain warrants that were issued in the previous equity financings. These warrants are denominated in US dollars, which is different than the functional currency of the Company. Under IFRS, they are classified as liabilities and any change in the fair value is recognized in the profit or loss. Changes in fair value result from volatility in the Company's share prices and fluctuations in the US/Canadian dollar exchange rates. Due to lower shares prices of the Company in the current quarter, this resulted in lower valuation for these warrants and a non-cash valuation gain for the current quarter.

Stock Based Compensation

For the current quarter, the Company recorded non-cash stock based compensation expenses of $300,000, compared to $189,000 for Q1 2011. The increase in stock based compensation expense was due to the issuance of a significant number of fully vested stock options in the current quarter.

Amortization, Depletion and Impairment Losses

For the current quarter, amortization, depletion and impairment losses were $691,000, compared to $718,000 for Q1 2011. Amortization and depletion of property and equipment for Q1 2012 was $681,000, compared to $709,000 for Q1 2011. Amortization and depletion expenses for the current quarter were comparable to the same quarter in prior year. Impairment losses for both quarters were recognized upon the expiry of certain leases for exploration and evaluation assets.

Net Loss and Operating Loss

The Company's net loss for the current quarter was $354,000 or $0.003 per share, compared to a net loss of $2,079,000 or $0.018 per share for the same quarter in 2011. The decrease in net loss was primarily due to the increase in revenues and the non-cash valuation gain of $1,110,000 from the decrease in fair value of warrant liability. This was partly offset by the increase in operating and transportation expenses.

The Company's operating loss for the current quarter was $1,455,000, compared to $1,196,000 for Q1 2011. The increase was primarily due to the increase in operating and transportation expenses. This was partly offset by the increase in revenues.

SUMMARY OF QUARTERLY RESULTS

The following summary for the eight most recently completed financial quarters ending March 31, 2012 details pertinent financial and corporate information, which is unaudited and prepared by management of the Company. For more detailed information, refer to related consolidated financial statements.

	1st Quarter ended March 31, 2012 $	4th Quarter ended December 31, 2011 $	3rd Quarter ended September 30, 2011 $	2nd Quarter ended June 30, 2011 $	1st Quarter ended March 31, 2011 $	4th Quarter ended December 31, 2010 $	3rd Quarter ended September 30, 2010 $	2nd Quarter ended June 30, 2010 $
Gross Revenues	1,928,000	2,478,000	2,947,000	1,816,000	1,584,000	1,529,000	2,534,000	2,676,000
Net loss for the period	(354,000)	(8,430,000)	(346,000)	(189,000)	(2,079,000)	(1,857,000)	(631,000)	(52,000)
Basic and diluted net loss per common share	(0.003)	(0.069)	(0.003)	(0.002)	(0.018)	(0.018)	(0.006)	(0.001)

Variations in gross revenues and net loss for the periods above resulted primarily from the following factors:

1. The production level of oil and natural gas and realized oil and natural gas prices resulted in the variations in gross revenues. Increased revenues in the quarter ending September 30, 2011 reflected increased oil production due to the achievement of full allowable oil production level set by the OGC.

2. The production level of oil and natural gas resulted in the variations in operating and transportation expenses. Corporate development activities and strategic initiatives taken was the result of the fluctuations in general and administrative expenses. These two factors are the causes for the variations in net loss. In the quarter ending December 31, 2011, the increase in general and administrative expenses was associated with the year-end bonus accrual for fiscal 2011; this partly caused the increase in net loss for the quarter.

3. Other non-cash items, such as amortization, depletion and impairment losses and valuation gain (loss) for the warrants denominated in US dollars, also resulted in the variations in net loss. Increased net loss for the quarter ended December 31, 2011 was mainly due to the recognition of non-cash impairment losses of $5.2 million and a non-cash valuation loss of $2 million.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments consist of cash and cash equivalents, accounts receivable, bank line of credit, accounts payable, accrued liabilities and warrant liabilities. Management has determined that the fair value of these financial instruments approximates their carrying values due to their immediate or short-term maturity. Net smelter royalties and related rights to earn or relinquish interests in mineral properties constitute derivative instruments. No value or discounts have been assigned to such instruments as there is no reliable basis to determine fair value until properties are in development or production and reserves have been determined.

From time to time, the Company enters into derivative contracts such as forwards, futures and swaps in an effort to mitigate the effects of volatile commodity prices and protect cash flows to enable funding of its exploration and development programs. Commodity prices can fluctuate due to political events, meteorological conditions, disruptions in supply and changes in demand.

The primary risks and how the Company mitigates them are as follows:

(a) Credit Risk

Credit risk arises from credit exposure from joint venture partners and oil & gas marketers included in accounts receivable. The maximum exposure to credit risk is equal to the carrying value of the financial assets.

The Company is exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Company, such failures may have a material adverse effect on the Company's business, financial condition, and results of operations.

The objective of managing the third party credit risk is to minimize losses in financial assets. The Company assesses the credit quality of the partners, taking into account their financial position, past experience, and other factors. The Company mitigates the risk of collection by obtaining the partners' share of capital expenditures in advance of a project and by monitoring accounts receivable on a regular basis. As at March 31, 2012, no accounts receivable has been deemed uncollectible or written off during the period. The Company expects to collect the outstanding receivables in the normal course of operations.

(b) Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they are due. The nature of the oil and gas industry is capital intensive and the Company maintains and monitors a certain level of cash flow to finance operating and capital expenditures.

The Company's ongoing liquidity and cash flow are impacted by various events and conditions. These events and conditions include but are not limited to commodity price fluctuations, general credit and market condition, operation and regulatory factors, such as government permits, the availability of drilling and other equipment, lands and pipeline access, weather, and reservoir quality.

To mitigate the liquidity risk, the Company closely monitors its credit facility, production level and capital expenditures to ensure that it has adequate liquidity to satisfy its financial obligations.

(c) Market Risk

Market risk is the risk that changes in market prices, such as foreign exchange rates, commodity prices, and interest rates will affect the Company's net earnings. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing returns. The Company utilizes financial derivatives to manage certain market risks. All such transactions are conducted in accordance with the risk management policy that has been approved by the Board of Directors.

(i) Foreign Currency Exchange Risk

Foreign currency exchange rate risk is the risk that the fair value of financial instruments or future cash flows will fluctuate as a result of changes in foreign exchange rates. Although substantially all of the Company's oil and natural gas sales are denominated in Canadian dollars, the underlying market prices in Canada for oil and natural gas are impacted by changes in the exchange rate between the Canadian and United States dollars. Given that changes in exchange rate have an indirect influence, the impact of changing exchange rates cannot be accurately quantified. The Company had no forward exchange rate contracts in place as at or during the three months ended March 31, 2012.

(ii) Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. During the three months ended March 31, 2012, the Company was exposed to interest rate fluctuations on its credit facility which bore a floating rate of interest. The Company had no interest rate swaps or financial contracts in place at or during the three months ended March 31, 2012.

(iii) Commodity Price Risk

Revenues and consequently cash flows fluctuate with commodity prices and the US/Canadian dollar exchange rate. Commodity prices are determined on a global basis and circumstances that occur in various parts of the world are outside of the control of the Company. The Company protects itself from fluctuations in prices by using the financial derivative sales contracts. The Company entered into commodity price contracts to manage the risks associated with price volatility and thereby protect its cash flows used to fund its capital program. The following table summarizes the Company's crude oil risk management positions at March 31, 2012:

Instrument type	Contract Month	Volume	Price per barrel
Western Texas Instrument ("WTI") Sold Futures	May 2012	4,000 barrels per month	US$103

FINANCIAL CONDITION, LIQUIDITY AND CAPITAL RESOURCES

Cash Balance and Cash Flow

The Company had cash and cash equivalents of $1,343,000 as at March 31, 2012. In addition to the cash balance, the Company has an unused line of credit of $0.9 million from a Canadian Bank.

Bank Line of Credit Financing

In September 2011, the Company obtained a $7 million revolving operating demand loan ("line of credit"), including a letter of credit facility to a maximum of $700,000 for a maximum one year term, from a Canadian Bank to refinance the bridge loan and to provide operating funds. The line of credit is at an interest rate of Prime + 1% (total 4% p.a. currently) and collateralized by a $10,000,000 debenture over all assets of DEAL and a $10,000,000 guarantee from Dejour Energy Inc. Subsequent to March 31, 2012, the Company renewed the line of credit with the Canadian Bank. The next review date is scheduled on or before September 30, 2012, but subject to change at the discretion of the bank. As at March 31, 2012, a total of $6.1 million of this facility was utilized.

According to the terms of the facility, DEAL is required to maintain an adjusted working capital ratio of greater than 1:1 at all times. The adjusted working capital ratio is defined as the ratio of (i) current assets (including any undrawn and authorized availability under the facility) less unrealized hedging gains to (ii) current liabilities (excluding current portion of outstanding balances of the facility) less unrealized hedging losses. As at March 31, 2012, the Company is in compliance with the working capital ratio requirement.

Working Capital Position

As at March 31, 2012	$
Working capital deficit	(6,516,000)
Non-cash warrant liability	850,000
Net cash working capital deficit	(5,666,000)

As at March 31, 2012, the Company had a working capital deficit of $6,516,000. Excluding the non-cash warrant liability of $850,000 related to the fair value of US$ denominated warrants issued in previous equity financings, the net working capital deficit was $5.7 million. The majority of the working capital deficit relates to outstanding bank line of credit.

The Company plans to remedy the deficiency through the following:

- Beginning in June 2011, oil production increased as a result of the waterflood at Woodrush. Oil production is expected to increase in late 2012, generating more cash flow for the Company.
- In May 2012, the Company has reached an agreement in principle with an U.S. institutional lender with respect to a US$14 million debt financing to fund the development of its U.S. oil and gas leases. Completion of the financing is subject to satisfactory completion of certain closing conditions.
- If necessary and at the right market conditions, the Company may fund its working capital through additional debt, equity or joint venture financing, or disposal of non-core assets.

Capital Resources

During the three months ended March 31, 2012, the Company successfully completed and tied into production the 3rd oil well and continued to optimize the waterflood at its Woodrush property in Canada. Most of the waterflood capital expenditures had already been spent in fiscal 2011. Future capital expenditures at Woodrush in the remainder of 2012 are expected to be approximately $1.2 to $1.5 million and funded through its cash flow from operations and the undrawn line of credit. In the U.S., the Company plans to drill up to eight wells during 2012 and its share of expenditures ranges from $6.5 to $11 million. The Company plans to fund the expenditures through additional financing, including debt, equity or joint venture financing, or disposal of non-core assets. Based on the availability of financing on favorable terms, the Company may adjust its future capital expenditure plans.

Contractual Obligations

As of March 31, 2012, and in the normal course of business we have obligations to make future payments, representing contracts and other commitments that are known and committed.

Contractual Obligations (in thousands of dollars)	2012	2013	2014	2015	2016	Thereafter	Total
	$	$	$	$	$	$	$
Operating lease obligations	184	141	49	-	-	Nil	374
Bank line of credit	6,126	-	-	-	-	Nil	6,126
Total	6,310	141	49	-	-	Nil	6,500

OFF-BALANCE SHEET ARRANGEMENTS

The Company has no material undisclosed off-balance sheet arrangements that have or are reasonably likely to have, a current or future effect on our results of operations or financial condition at March 31, 2012.

RELATED PARTY TRANSACTIONS

Except as disclosed elsewhere, during the three months ended March 31, 2012 and 2011, the Company entered into the following transactions with related parties:

a) Compensation awarded to key management included a total of salaries and consulting fees of $312,642 (2011 - $312,808) and non-cash stock-based compensation of $53,138 (2011 - $113,079). Key management includes the Company's officers and directors. The salaries and consulting fees are included in general and administrative expenses. Included in accounts payable and accrued liabilities at March 31, 2012 is $Nil (December 31, 2011 - $396,618) owing to the companies controlled by the officers of the Company.

b) The Company incurred a total of $Nil (2011 - $2,301) in finance costs to a company controlled by an officer of the Company.

c) Included in interest and other income is $7,500 (2011 - $7,500) received from the companies controlled by officers of the Company for rental income.

d) In December 2009, a company controlled by the CEO of the Company ("HEC") became a 5% working interest partner in the Woodrush property. Included in accounts receivable at March 31, 2012 is $3,366 (December 31, 2011 - $Nil) owing from HEC. Included in accounts payable and accrued liabilities at March 31, 2012 is $3,084 (December 31, 2011 - $53,668) owing to HEC.

e) With respect to the private placement of 11,010,000 units issued at US$0.30 per unit completed in February 2011, directors and officers of the Company purchased 2,000,000 units of this offering (see Note 13 to the annual consolidated financial statements for details).

f) In December 2011, HEC exercised 250,000 warrants with an exercise price of US$0.35 each that were issued in February 2011.

g) In January 2012, directors and officers of the Company exercised 750,000 warrants with an exercise price of US$0.35 each that were issued in February 2011.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

On January 1, 2011, the Company adopted IFRS for financial reporting purposes, with a transition date of January 1, 2010. The consolidated financial statements for the year ended December 31, 2011, including required comparative information, were prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB") and interpretations of the International Financial Reporting Interpretations Committee ("IFRIC"). Previously, the Company prepared its financial statements in accordance with Canadian GAAP. Unless otherwise noted, 2010 comparative financial statement information has been prepared in accordance with IFRS.

The adoption of IFRS did not have a material impact on the Company's operations, strategic decisions, cash flow and capital expenditures. The most significant changes to the Company's accounting policies related to the accounting for its property, plant and equipment and accounting for derivative financial instruments. Other impacted areas include stock-based compensation, foreign currency translation and accounting for flow through shares.

Further information on the IFRS accounting policies, impacts and reconciliation between previous Canadian GAAP and IFRS are provided in the Company's Annual Consolidated Financial Statements for the year ended December 31, 2011 and which was also discussed in the Company's Annual MD&A for the year ended December 31, 2011, both which are filed on SEDAR at www.sedar.com.

CRITICAL ACCOUNTING ESTIMATES

The Company makes estimates and assumptions about the future that affect the reported amounts of assets and liabilities. Estimates and judgments are continually evaluated based on historical experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. In the future, actual experience may differ from these estimates and assumptions.

The effect of a change in an accounting estimate is recognized prospectively by including it in profit or loss in the period of the change, if the change affects that period only; or in the period of the change and future periods, if the change affects both.

Information about critical judgments in applying accounting policies that have the most significant risk of causing material adjustment to the carrying amounts of assets and liabilities recognized in the condensed interim consolidated financial statements within the next financial year are discussed below:

Reserves

The estimate of reserves is used in forecasting the recoverability and economic viability of the Company's oil and gas properties, and in the depletion and impairment calculations. The process of estimating reserves is complex and requires significant interpretation and judgment. It is affected by economic conditions, production, operating and development activities, and is performed using available geological, geophysical, engineering, and economic data. Reserves are evaluated at least annually by the Company's independent reserve evaluators and updates to those reserves, if any, are estimated internally. Future development costs are estimated using assumptions as to the number of wells required to produce the commercial reserves, the cost of such wells and associated production facilities and other capital costs.

Exploration and evaluation expenditures

The application of the Company's accounting policy for exploration and evaluation expenditure requires judgment in determining whether it is likely that future economic benefits will flow to the Company, which is based on assumptions about future events or circumstances. Estimates and assumptions made may change if new information becomes available. If, after expenditure is capitalized, information becomes available suggesting that the recovery of the expenditure is unlikely, the amount capitalized is written off in profit or loss in the period the new information becomes available.

Impairment

A CGU is defined as the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The allocation of assets into CGUs requires significant judgment and interpretations with respect to the integration between assets, the existence of active markets, similar exposure to market risks, shared infrastructures, and the way in which management monitors the operations. The recoverable amounts of CGUs and individual assets have been determined based on the higher of fair value less costs to sell or value-in-use calculations. The key assumptions the Company uses in estimating future cash flows for recoverable amounts are anticipated future commodity prices, expected production volumes, future operating and development costs. Changes to these assumptions will affect the recoverable amounts of CGUs and individual assets and may then require a material adjustment to their related carrying value.

Derivative Financial Instruments

When estimating the fair value of derivative financial instruments, the Company uses third-party models and valuation methodologies that utilize observable market data. In addition to market information, the Company incorporates transaction specific details that market participants would utilize in a fair value measurement, including the impact of non-performance risk. However, these fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

Decommissioning liability

Decommissioning provisions have been recognized based on the Company's internal estimates. Assumptions, based on the current economic environment, have been made which management believes are a reasonable basis upon which to estimate the future liability. These estimates take into account any material changes to the assumptions that occur when reviewed regularly by management. Estimates are reviewed at least annually and are based on current regulatory requirements. Significant changes in estimates of contamination, restoration standards and techniques will result in changes to provisions from period to period. Actual decommissioning costs will ultimately depend on future market prices for the decommissioning costs which will reflect the market conditions at the time the decommissioning costs are actually incurred. The final cost of the currently recognized decommissioning provisions may be higher or lower than currently provided for.

Income taxes

The Company recognizes the net future tax benefit related to deferred tax assets to the extent that it is probable that the deductible temporary differences will reverse in the foreseeable future. Assessing the recoverability of deferred tax assets requires the Company to make significant estimates related to expectations of future taxable income. Estimates of future taxable income are based on forecast cash flows from operations and the application of existing tax laws in each jurisdiction. To the extent that future cash flows and taxable income differ significantly from estimates, the ability of the Company to realize the net deferred tax assets recorded at the reporting date could be impacted. Additionally, future changes in tax laws in the jurisdictions in which the Company operates could limit the ability of the Company to obtain tax deductions in future periods. All tax filings are subject to audit and potential reassessment. Accordingly, the actual income tax liability may differ significantly from the estimated and recorded amounts.

Share-based payment transactions

The Company measures the cost of equity-settled transactions with employees by reference to the fair value of the equity instruments at the date at which they are granted. Estimating fair value for share-based payment transactions requires determining the most appropriate valuation model, which is dependent on the terms and conditions of the grant. This estimate also requires determining the most appropriate inputs to the valuation model including the expected life of the share option, volatility and dividend yield.

DISCLOSURE OF INTERNAL CONTROLS

The Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of the Company's disclosure controls and procedures as at March 31, 2012. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective as at March 31, 2012 to provide reasonable assurance that material information relating to the Company, including its consolidated subsidiaries, would be made known to them.

INTERNAL CONTROL OVER FINANCIAL REPORTING

The Chief Executive Officer and Chief Financial Officer are responsible for establishing and maintaining internal control over financial reporting ("ICFR"), as such term is defined in NI 52-109, for the Company. They have, as at March 31, 2012, designed ICFR, or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Chief Executive Officer and Chief Financial Officer of the Company are able to certify the design of the Company's internal control over financial reporting with no significant weaknesses in design of these internal controls that require commenting on in the MD&A.

It should be noted that while the officers believe that the Company's controls provide a reasonable level of assurance with regard to their effectiveness, they do not expect that the disclosure controls and procedures or internal controls over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

During the three months ended March 31, 2012, the Company continued to improve the period end review process and staff training to mitigate the weaknesses in ICFR previously identified.

Previously, period end review of the interim financial statements by management did not identify the error in the statement of cash flows for the three months ended March 31 2011. Accordingly, cash flows from (used in) operating activities for the three months ended March 31, 2011 have been decreased by $1,652,825 and cash flows from (used in) investing activities have been increased by $1,652,825. The error has already been corrected in the interim financial statements for the three months ended March 31 2012. This error had no impact on reported assets (including total cash and cash equivalents), liabilities, shareholders' equity, revenues, expenses, net and comprehensive loss for the period or net loss per common share basic and diluted.

With the improvement in operation of these controls, the Company believes it has mitigated the control weaknesses identified.

Except the above, there were no changes in the Company's internal control over financial reporting that occurred during the three months ended March 31, 2012 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

The Board of Directors, through its Audit Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Audit Committee is composed of three independent directors who review accounting, auditing, internal controls and financial reporting matters.

WHISTLEBLOWER POLICY

Effective December 28, 2007, the Company's Audit Committee adopted resolutions that authorized the establishment of procedures for complaints received regarding accounting, internal controls or auditing matters, and for a confidential, anonymous submission procedure for employees and consultants who have concerns regarding questionable accounting or auditing matters. The implementation of the whistleblower policy is in accordance with the new requirements pursuant to Multilateral Instrument 52-110 Audit Committees, national Policy 58-201 Corporate Governance Guidelines and National Instrument 58-101 Disclosure of Corporate Governance Practices.

NON-GAAP MEASURES

Non-GAAP measures are commonly used in the oil and gas industry. Certain measures in this document do not have any standardized meaning as prescribed by IFRS and previous GAAP such as Operating Cash Flow, Operating Netback, Operating Loss, EBITDA and Adjusted EBITDA and therefore are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this document in order to provide shareholders and potential investors with additional information regarding our liquidity and our ability to generate funds to finance our operations.

Operating Cash Flow is a non-GAAP measure defined as cash flow from operating activities before changes in non-cash operating working capital items.

Operating Netback is a non-GAAP measure defined as gross revenues less royalties and operating and transportation expenses.

Operating Loss is a non-GAAP measure defined as net loss excluding non-cash items that management believes affects the comparability of operating results. These items may include, but are not limited to, unrealized financial instrument gain (loss), impairment losses and impairment reversals, gain (loss) on divestitures, and change in fair value of financial instruments.

EBITDA is a non-GAAP measure defined as net loss before income tax expense, finance costs, and amortization, depletion and impairment losses.

Adjusted EBITDA excludes certain items that management believes affect the comparability of operating results. Items excluded generally are non-cash items, one-time items or items whose timing or amount cannot be reasonably estimated.

BOE PRESENTATION

Barrel of oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of gas to one barrel of oil. The term "BOE" may be misleading if used in isolation. A BOE conversion ratio of one barrel of oil to six mcf of gas is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well head.

Total BOEs are calculated by multiplying the daily production by the number of days in the period.

FORWARD LOOKING STATEMENTS

Statements contained in this document about oil and gas production and operating activities that may constitute "forward-looking statements" or “forward-looking information” within the meaning of applicable securities legislation as they involve the implied assessment that the resources described can be profitably produced in the future, based on certain estimates and assumptions. Forward-looking statements are based on current expectations, estimates and projections that involve a number of risks, uncertainties and other factors that could cause actual results to differ materially from those anticipated by the Company and described in the forward-looking statements. These risks, uncertainties and other factors include, but are not limited to, adverse general economic conditions, operating hazards, drilling risks, inherent uncertainties in interpreting engineering and geologic data, competition, reduced availability of drilling and other well services, fluctuations in oil and gas prices and prices for drilling and other well services, government regulation and foreign political risks, fluctuations in the exchange rate between Canadian and US dollars and other currencies, as well as other risks commonly associated with the exploration and development of oil and gas properties. Additional information on these and other factors, which could affect the Company’s operations or financial results, are included in the Company’s reports on file with Canadian and United States securities regulatory authorities. We assume no obligation to update forward-looking statements should circumstances or management's estimates or opinions change unless otherwise required under securities law.

ABBREVIATIONS

In this MD&A, the following abbreviations commonly used in the oil & gas industry have the meanings indicated:

Oil and Natural Gas Liquids		Natural Gas	
bbl	barrel	Mcf	thousand cubic feet
bbls	barrels	MCFD	thousand cubic feet per day
BOP/D	barrels per day	MMcf	million cubic feet
Mbbls	thousand barrels	MMcf/D	million cubic feet per day
Mmbtu	million British thermal units	Mcfe	Thousand cubic feet of gas equivalent

Other

AECO	Intra-Alberta Nova Inventory Transfer Price (NIT net price of natural gas).
BOE	Barrels of oil equivalent. A barrel of oil equivalent is determined by converting a volume of natural gas to barrels using the ratio of 6 Mcf to one barrel.
BOE/D	Barrels of oil equivalent per day.
BCF	Billion cubic feet
BCFE	Billion cubic feet equivalent
MBOE	Thousand barrels of oil equivalent.
NYMEX	New York Mercantile Exchange.
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing Oklahoma for crude oil of standard grade.