DEJOUR ENERGY INC.
RESOURCEFUL. ENTERPRISING.

(formerly operating as Dejour Enterprises Ltd.)

MANAGEMENT DISCUSSION AND ANALYSIS

For the Year Ended December 31, 2011

Date of Report: March 29, 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. 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"), which are also generally accepted accounting principles ("GAAP") for publicly accountable enterprises in Canada. In accordance with the standard related to the first time adoption of IFRS, the Company's transition date to IFRS was January 1, 2010 and therefore the comparative information for 2010 has been prepared in accordance with IFRS accounting policies.

This Management's Discussion and Analysis ("MD&A") and the annual Consolidated Financial Statements and comparative information have been prepared in accordance with IFRS. For all periods up to and including the year ended December 31, 2010, the Company prepared the Consolidated Financial Statements in accordance with Canadian generally accepted accounting principles ("Pre-changeover Canadian GAAP" or "Previous GAAP"). The term "previous GAAP" refers to Canadian GAAP before the adoption of IFRS. Within this MD&A, the financial information prior to January 1, 2010 has been prepared following Canadian GAAP and, as allowed under IFRS 1, has not been re-presented. Further information regarding IFRS accounting policies can be found in the Changes in the Accounting Policies section, below, of this MD&A and the Notes to the Consolidated Financial Statements for the year ended December 31, 2011.

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 2011 significant progress was made on two of our Piceance Basin properties in the United States. In particular, the first drilling permits for the Kokopelli Field were delivered in October 2011, allowing the Company to maintain its schedule for production startup in the second half of 2012. At South Rangely Field, a new liquids rich gas field was discovered with the drilling of the Dejour Federal 36-24 Well. The Company is currently planning for additional drilling at South Rangely in 2012 to both increase production and to better delineate the reservoir. Despite the current weakness in North American natural gas prices, the Company remains committed to first production from South Rangely and Kokopelli Field in 2012, as important steps in the execution of Dejour's business plan. A plan designed to generate sustainable growth through the investment in low risk development opportunities on current land holdings, supplemented with potentially leveraging investments in new opportunities within North America.

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. These two developments provide the most effective way to generate positive returns while positioning the Company for a broad uplift in value as gas prices recover from current lows. Though 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 prudent but leveraging 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 to enhance long term shareholder value.

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.

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 113,000 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.

2011 HIGHLIGHTS

In 2011, the Company's focus was on production optimization of the Drake/Woodrush property, while finalizing pre-drilling activities for the Kokopelli development and drilling a successful discovery well at South Rangely.

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

1. Successful implementation and expansion of the Halfway "E" oil pool waterflood on the Company's Woodrush property.

2. Obtained a $7 million line of credit from a Canadian bank to refinance the bridge loan and to provide funds for general corporate purposes.

3. Generated positive operating cash flow for the second half of the year.

4. In September, the Company completed all requirements for drilling on its federal leases at Gibson Gulch, Piceance Basin, Colorado, resulting in the first drilling permits being issued in the fourth quarter of 2011.

5. In December, the Company completed and tested a discovery well at South Rangely. After the well was successfully fractured and stimulated, the well flowed rich gas from the Mancos "B" Sand in commercial quantities.

SELECTED CONSOLIDATED FINANCIAL RESULTS

	Year ended December 31,	
	2011	2010
	$	$
Gross Revenues	8,824,000	8,086,000
Net Loss	(11,043,000)	(5,124,000)
Operating Cash Flow [(1)]	(322,000)	(142,000)
Operating Loss [(1)]	(3,215,000)	(4,000,000)
Adjusted EBITDA	532,000	536,000

[(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 2011, 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 December 2010, a waterflood project application was expedited and approval was received. The project was implemented in early 2011 with water injection commencing in March 2011. In the first quarter of 2011, gross production from the field was reduced to approximately 544 barrels of oil equivalent/day ("BOED") (408 BOED net) in response to the decreasing pressure in the Halfway oil sand. In October, 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 on oil production as the oil production is gradually ramped up to its maximum level in the second half of 2012.

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 which 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 Kokopelli.

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 103,000 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 December 31, 2011	Three months ended December 31, 2010	Year ended December 31, 2011	Year ended December 31, 2010
	$	$	$	$
Land acquisition and retention	37,197	31,337	241,911	272,837
Drilling and completion	1,853,487	1,113,000	4,397,819	2,206,270
Facility and pipelines	290,381	331,799	2,949,008	1,243,616
Capitalized general and administrative	168,403	145,620	742,771	1,289,043
Other assets	148	(15,261)	28,867	26,945
	2,349,616	1,606,495	8,360,376	5,038,711

DAILY PRODUCTION

	Three months ended December 31, 2011	Three months ended December 31, 2010	Year ended December 31, 2011	Year ended December 31, 2010
By Product				
Natural gas (mcf/d)	1,376	1,614	1,184	1,504
Oil and natural gas liquids (bbls/d)	242	149	223	236
Total (boe/d)	471	418	421	487

The decrease in natural gas production for the year ended December 31, 2011 ("fiscal 2011") was primarily the result of the temporary curtailment of production due to maintenance related downtime at the regional gas processing plant in the 2nd quarter of 2011 and extended to the third week of July 2011. This regional gas processing plant is operated by a third party and is not under the Company's control. Gas production resumed during the third week of July 2011. The decrease in natural gas production for the current quarter was because gas production is restricted to a maximum daily limit, due to 100% compressor capacity.

The decrease in oil production for the current year was the result of production restrictions imposed by the Oil and Gas Conservation Commission of British Columbia ("OGC") on the Company's Woodrush property prior to the successful implementation of the waterflood in the Halfway "E" Pool. The increase in oil production for the current quarter was due to the response of the Halfway "E" Pool to water injection that commenced in March 2011.

SELECTED ANNUAL INFORMATION

The Company adopted and transitioned to IFRS as of January 1, 2010. The comparative period for fiscal 2010 has been restated in accordance with IFRS as part of the transition to IFRS. The reconciliation from Previous GAAP to IFRS is included in Note 25 in the notes to the consolidated financial statements.

Consolidated balance sheets	In accordance with IFRS		In accordance with previous GAAP
	As at December 31,		As at December 31,
	2011	2010	2009
	$	$	$
Total assets	29,438,000	30,413,000	45,886,000
Long-term obligation	-	-	2,345,000

Consolidated statements of comprehensive loss	In accordance with IFRS		In accordance with previous GAAP
	Years ended December 31,		Year ended December 31,
	2011	2010	2009
	$	$	$
Gross revenues	8,824,000	8,086,000	6,471,000
Net loss for the year	(11,043,000)	(5,124,000)	(12,807,000)
Loss per common share, basic and diluted	(0.092)	(0.051)	(0.162)

The Company has not declared any cash dividends since inception.

SHARE CAPITAL

The following is a summary of share transactions for the year ended December 31, 2011 and December 31, 2010:

	Common Shares	$
Balance at January 1, 2010	95,791,038	**75,810,350**
- Shares issued via private placements, net of issuance costs	14,389,507	3,983,508
- Flow through share liability	-	(407,975)
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
- Warrant liability reallocated on exercise of warrants	-	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**

As at March 29, 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, 2010	4,416,682	0.45
Options granted	3,573,000	0.35
Options cancelled (forfeited)	(400,000)	0.39
Options expired	(643,182)	0.46
Balance at December 31, 2010	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

Details of the outstanding and exercisable stock options as at December 31, 2011 are as follows:

	Outstanding			Exercisable		
	Number of options	Weighted average exercise price	Weighted average contractual life (years)	Number of options	Weighted average exercise price	Weighted average contractual life (years)
		$			$	
$0.35	5,185,500	0.35	2.66	3,870,500	0.35	2.81
$0.45	3,318,500	0.45	2.13	2,012,275	0.45	2.10
	8,504,000	0.39	2.45	5,882,775	0.38	2.57

As at December 31, 2011, all the outstanding and exercisable stock options were “in the money” (the exercise price was less than the market trading price). If these options were fully exercised, the Company would realize approximately $2,260,000 in additional capital.

The following table summarizes information about outstanding warrant transactions:

	Number of Warrants	Weighted average Exercise price
		$
Balance at January 1, 2010	14,736,150	0.47
Warrants granted	6,274,305	0.41
Balance at December 31, 2010	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

Details of the outstanding and exercisable warrants as at December 31, 2011 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	3.88	3,642,856	0.40	3.88
$0.55	4,015,151	0.55	2.48	4,015,151	0.55	2.48
$0.35 US	2,419,584	0.36	0.09	2,419,584	0.36	0.09
$0.40 US	7,700,000	0.41	2.98	7,700,000	0.41	2.98
$0.46 US	645,999	0.47	2.84	645,999	0.47	2.84
	18,423,590	0.43	2.66	18,423,590	0.43	2.66

SELECTED FINANCIAL HIGHLIGHTS

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

Operating Cash Flow

	Three months ended December 31, 2011	Three months ended December 31, 2010	Year ended December 31, 2011	Year ended December 31, 2010
	$	$	$	$
Cash from (used) in operating activities - GAAP	294,000	624,000	(396,000)	346,000
Less: changes in non-cash working capital	545,000	1,030,000	(74,000)	488,000
Operating Cash Flow – Non-GAAP	(251,000)	(406,000)	(322,000)	(142,000)

Operating Netback

	Three months ended December 31, 2011	Three months ended December 31, 2010	Year ended December 31, 2011	Year ended December 31, 2010
	$	$	$	$
Revenues	2,478,000	1,528,000	8,824,000	8,086,000
Less: Royalties	(429,000)	(178,000)	(1,628,000)	(1,312,000)
Less: Operating and transportation expenses	(857,000)	(559,000)	(2,499,000)	(2,609,000)
Operating Netback	1,192,000	791,000	4,697,000	4,165,000

Operating Loss

	Three months ended December 31, 2011	Three months ended December 31, 2010	Year ended December 31, 2011	Year ended December 31, 2010
	$	$	$	$
Net loss	(8,430,000)	(1,857,000)	(11,043,000)	(5,124,000)
Add back (losses) and deduct gains:				
Impairment losses	5,212,000	769,000	6,248,000	1,192,000
Change in fair value of warrant liability	2,044,000	(18,000)	1,580,000	(68,000)
Operating Loss	(1,174,000)	(1,106,000)	(3,215,000)	(4,000,000)

EBITDA

	Three months ended December 31, 2011	2010	Year ended December 31, 2011	2010
	$	$	$	$
Net loss	(8,430,000)	(1,857,000)	(11,043,000)	(5,124,000)
Deferred income tax recovery	-	(221,000)	(187,000)	(492,000)
Finance costs	72,000	243,000	868,000	1,092,000
Amortization, depletion and impairment losses	6,019,000	1,556,000	8,652,000	4,685,000
EBITDA	(2,339,000)	(279,000)	(1,710,000)	(161,000)

Adjusted EBITDA

	Three months ended December 31, 2011	2010	Year ended December 31, 2011	2010
	$	$	$	$
EBITDA	(2,339,000)	(279,000)	(1,710,000)	(161,000)
Adjustments:				
Non-cash stock-based compensation	113,000	134,000	662,000	765,000
Change in fair value of warrant liability	2,044,000	(18,000)	1,580,000	(68,000)
Adjusted EBITDA	(182,000)	(163,000)	532,000	536,000

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 net cash provided by operating activities before changes in non-cash operating working capital items.

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

Operating Loss is a non-GAAP measure defined as net income (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 income (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 DECEMBER 31, 2011 AND 2010

Summary of Operational Highlights

DEAL Production and Netback Summary

	Three Months Ended December 31, 2011	2010
Production Volumes:		
Oil and natural gas liquids (bbls)	22,241	13,698
Gas (mcf)	126,633	148,489
Total (BOE)	43,346	38,445
Average Price Received:		
Oil and natural gas liquids ($/bbls)	93.00	71.17
Gas ($/mcf)	3.23	3.73
Total ($/BOE)	57.15	39.76
Royalties ($/BOE)	9.90	4.64
Operating and Transportation Expenses ($/BOE)	19.78	14.54
Netbacks ($/BOE)*	27.48	20.58

*See Non-GAAP Measures

Revenues

	Three months ended December 31, 2011	2010
Revenue		
Gross revenues	**$ 2,478,000**	$ 1,528,000
Royalties	**(429,000)**	(178,000)
Revenues, net of royalties	**2,049,000**	1,350,000
Financial instrument gain	**-**	7,000
Other income	**8,000**	11,000
Total revenue	**$ 2,057,000**	$ 1,368,000

For the three months ended December 31, 2011 ("Q4 2011"), the Company recorded $2,478,000 in oil and natural gas sales as compared to $1,528,000 in oil and natural gas sales for the three months ended December 31, 2010 ("Q4 2010"). 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 gas production is restricted to a maximum daily limit, due to 100% compressor capacity.

Royalties for Q4 2011 increased to $429,000 from $178,000 for Q4 2010, 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 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 December 31, 2011 and 2010:

	Three months ended December 31, 2011	2010
Dejour Realized Average Prices		
Natural gas ($/mcf)	$ 3.23	$ 3.73
Oil and natural gas liquids ($/bbl)	93.00	71.17
Total average price ($/boe)	$ 57.15	$ 39.76
Average Benchmark Prices		
Edmonton Par ($/bbl)	$ 97.87	$ 80.73
Natural gas - AECO-C Spot ($ per mcf)	$ 3.47	$ 3.58

For the current quarter, Dejour's average realized natural gas prices reflected lower benchmark prices compared to Q4 2010. Oil prices received for Q4 2011 increased to $93.00 per barrel ("bbl"), compared to $71.17 per bbl for Q4 2010. 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 Q4 2011 increased to $857,000 from $559,000 for Q4 2010. The increase was due to the increase in oil production, increased repairs and maintenance of oil wells, and the addition of water hauling for the waterflood.

General and Administrative Expenses

General and administrative expenses for Q4 2011 increased to $1,374,000 from $957,000 for Q4 2010. The increase was mainly due to the year-end bonus accrual for fiscal 2011.

Finance Costs and Change in Fair Value of Warrant Liability

Finance costs for the current quarter decreased to $72,000 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 Q4 2011 was a loss of $2,044,000, compared to a gain of $18,000 for Q4 2010, primarily due to the increase 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 higher shares prices of the Company in the current quarter, this resulted in higher valuation for these warrants and a non-cash valuation loss for the current quarter.

Amortization, Depletion and Impairment Losses

For the current quarter, amortization, depletion and impairment losses were $6,019,000, compared to $1,556,000 for Q4 2010. Amortization and depletion of property and equipment for Q4 2011 was $807,000, compared to $787,000 for Q4 2010. Amortization and depletion expenses for the current quarter were comparable to the same quarter in prior year. Impairment losses of $5,212,000 for Q4 2011 were recognized because the carrying value of certain property and equipment and exploration and evaluation assets exceeded their recoverable amounts, while the impairment losses of $769,000 for Q4 2010 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 $8,430,000 or $0.069 per share, compared to a net loss of $1,857,000 or $0.018 per share for the same quarter in 2010. The increase in net loss was primarily due to the recognition of non-cash impairment losses of $5,212,000 and non-cash valuation loss of $2,044,000 from the increase in fair value of warrant liability. This was partly offset by the increase in revenues.

The Company's operating loss for the current quarter was comparable to the same quarter in prior year.

RESULTS OF OPERATIONS – YEAR ENDED DECEMBER 31, 2011 AND 2010

Summary of Operational Highlights

DEAL Production and Netback Summary

	Year Ended December 31, 2011	2010
Production Volumes:		
Oil and natural gas liquids (bbls)	81,468	86,119
Gas (mcf)	432,199	548,890
Total (BOE)	153,501	177,599
Average Price Received:		
Oil and natural gas liquids ($/bbls)	88.98	67.46
Gas ($/mcf)	3.64	4.13
Total ($/BOE)	57.49	45.53
Royalties ($/BOE)	10.61	7.39
Operating and Transportation Expenses ($/BOE)	16.18	14.67
Netbacks ($/BOE)*	30.70	23.48

*See Non-GAAP Measures

Revenues

	Year ended December 31, 2011	2010
Revenue		
Gross revenues	**$ 8,824,000**	$ 8,086,000
Royalties	**(1,628,000)**	(1,312,000)
Revenues, net of royalties	**7,196,000**	6,774,000
Financial instrument gain (loss)	**(59,000)**	68,000
Other income	**34,000**	36,000
Total revenue	**$ 7,171,000**	$ 6,878,000

For fiscal 2011, the Company recorded $8,824,000 in oil and natural gas sales as compared to $8,086,000 in oil and natural gas sales for the year ended December 31, 2010 ("fiscal 2010"). The increase in gross revenues was due to higher realized oil prices in 2011. This was partly offset by lower oil and gas production for the current year.

Royalties for fiscal 2011 increased to $1,628,000 from $1,312,000 for fiscal 2010. The increase was attributable to higher oil revenue and the increase in the proportion of revenue attributed to oil. Oil production 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 year ended December 31, 2011 and 2010:

		Year ended December 31,		
		2011		2010
Dejour Realized Average Prices				
Natural gas ($/mcf)	$	3.64	$	4.13
Oil and natural gas liquids ($/bbl)		88.98		67.46
Total average price ($/boe)	$	57.49	$	45.53
Average Benchmark Prices				
Edmonton Par ($/bbl)	$	95.16	$	77.81
Natural gas - AECO-C Spot ($ per mcf)	$	3.67	$	4.13

For the current year, Dejour's average realized natural gas prices reflected lower benchmark prices compared to fiscal 2010. Oil prices received for fiscal 2011 increased to $88.98 per barrel ("bbl"), compared to $67.46 per bbl for fiscal 2010.

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 fiscal 2011 decreased to $2,499,000 from $2,609,000 for fiscal 2010. The decrease was due to lower oil and gas production. Operating costs per BOE for both years were comparable despite lower oil and gas production.

General and Administrative Expenses

General and administrative expenses for fiscal 2011 increased to $4,042,000 from $3,383,000 for fiscal 2010. The increase was mainly due to the year-end bonus accrual for fiscal 2011 and the non-recurring professional fees associated with the required conversion to the International Financial Reporting Standards (IFRS).

Finance Costs and Change in Fair Value of Warrant Liability

Finance costs for fiscal 2011 decreased to $868,000 from $1,092,000 for fiscal 2010. 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 fiscal 2011 was a loss of $1,580,000, compared to a gain of $68,000 for fiscal 2010. 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 higher market prices for the Company's common shares towards the end of the year, this resulted in higher valuation for these warrants and a non-cash valuation loss for fiscal 2011.

Amortization, Depletion and Impairment Losses

For fiscal 2011, amortization, depletion and impairment losses were $8,652,000, compared to $4,685,000 for fiscal 2010. Amortization and depletion of property and equipment for fiscal 2011 was $2,404,000, compared to $3,493,000 for fiscal 2010. The decrease in amortization and depletion expenses was mainly due to the increased reserves in the Woodrush property at December 31, 2011 and the decrease in production. Impairment losses of $6,248,000 for fiscal 2011 were recognized because the carrying value of certain property and equipment and exploration and evaluation assets exceeded their recoverable amounts, while the impairment losses of $1,192,000 for fiscal 2010 were recognized upon the expiry of certain leases for exploration and evaluation assets and property and equipment.

Net Loss and Operating Loss

The Company's net loss for fiscal 2011 was $11,043,000 or $0.092 per share, compared to a net loss of $5,124,000 or $0.051 per share for fiscal 2010. The increase in net loss was primarily due to the recognition of non-cash impairment losses of $6,248,000 and non-cash valuation loss of $1,580,000 from the increase in fair value of warrant liability. This was partly offset by the increase in revenues.

The Company's operating loss for fiscal 2011 was $3,215,000, compared to $4,000,000 for fiscal 2010. The decrease was primarily due to lower amortization and depletion of property and equipment for the current year, as a result of the increased reserves in the Company's Woodrush property.

SUMMARY OF QUARTERLY RESULTS

The following summary for the eight most recently completed financial quarters ending December 31, 2011 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.

	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 $	1st Quarter ended March 31, 2010 $
Gross Revenues	2,478,000	2,947,000	1,816,000	1,584,000	1,529,000	2,534,000	2,676,000	1,347,000
Net loss for the period	(8,430,000)	(346,000)	(189,000)	(2,079,000)	(1,857,000)	(631,000)	(52,000)	(2,584,000)
Basic and diluted net loss per common share	(0.069)	(0.003)	(0.002)	(0.018)	(0.018)	(0.006)	(0.001)	(0.026)

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 current quarter, the increase in general and administrative expenses was associated with the year-end bonus accrual for fiscal 2011.

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 current quarter was mainly due to the recognition of non-cash impairment losses of $5.2 million and a non-cash valuation loss of $2 million.

FOURTH QUARTER ANALYSIS

The loss for the quarter ending December 31, 2011, when compared with the other quarters, was the result of the recognition of non-cash impairment losses of $5.2 million and a non-cash valuation loss of $2 million for the warrants denominated in US dollars in the quarter. In the current quarter, the Company also received $2 million from the exercise of warrants and options.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments consist of cash and cash equivalents, accounts receivable, bank line of credit, and accounts payable and accrued 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 December 31, 2011, 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) 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 December 31, 2011:

Instrument type	Contract Month	Volume	Price per barrel
Western Texas Instrument ("WTI") Sold Futures	February 2012	4,000 barrels per month	US$98
Western Texas Instrument ("WTI") Sold Futures	March 2012	4,000 barrels per month	US$98
Western Texas Instrument ("WTI") Sold Futures	April 2012	4,000 barrels per month	US$98

FINANCIAL CONDITION, LIQUIDITY AND CAPITAL RESOURCES

Cash Balance and Cash Flow

The Company had cash and cash equivalents of $2,488,000 as at December 31, 2011. In addition to the cash balance, the Company has an unused line of credit of $1.5 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. In December 2011, the Company renewed the line of credit with the Canadian Bank. The next review date is scheduled on or before May 1, 2012, but subject to change at the discretion of the bank. As at December 31, 2011, a total of $5.5 million of this facility was utilized.

According to the terms of the facility, DEAL is required to maintain a working capital ratio of greater than 1:1 at all times. The 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 December 31, 2011, the Company is in compliance with the working capital ratio requirement.

Working Capital Position

As at December 31, 2011	$
Working capital deficit	(7,756,000)
Non-cash warrant liability	2,245,000
Net cash working capital deficit	(5,511,000)

As at December 31, 2011, the Company had a working capital deficit of $7,756,000. Excluding the non-cash warrant liability of $2,245,000 related to the fair value of US$ denominated warrants issued in previous equity financings, the working capital deficit mainly consisted of $5.5 million used demand line of credit with a $7 million credit limit. As at December 31, 2011, $1.5 million remains unused. The Company plans to remedy the deficiency through the following:

- Subsequent to December 31, 2011, the Company received $1,200,000 from the exercise of warrants and options.
- Beginning in June 2011, oil production increased as a result of the waterflood at Woodrush. Oil production is expected to increase in 2012, generating more cash flow for the Company.
- 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 year ended December 31, 2011, the Company continued to optimize the waterflood at its Woodrush property in Canada. Most of the waterflood capital expenditures have already been spent in fiscal 2011. Future capital expenditures at Woodrush in the upcoming year 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.

Contractual Obligations

As of December 31, 2011, 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	223	107	49	-	-	Nil	379
Bank line of credit	5,545	-	-	-	-	Nil	5,545
Total	5,768	107	49	-	-	Nil	5,924

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 December 31, 2011.

RELATED PARTY TRANSACTIONS

Except as disclosed elsewhere, during the year ended December 31, 2011 and 2010, 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 $1,771,981 (2010 - $1,215,191) and non-cash stock-based compensation of $451,071 (2010 - $486,018). 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 December 31, 2011 is $396,618 (December 31, 2010 - $12,000 and January 1, 2010 - $Nil) owing to a company controlled by an officer of the Company.

b) The Company incurred a total of $2,301 (2010 - $268,440) in finance costs to a company controlled by an officer of the Company.

c) Included in interest and other income is $30,000 (2010 - $30,000) received from the companies controlled by officers of the Company for rental income.

d) In July 2008, Brownstone Ventures Inc. ("Brownstone") became a 28.53% working interest partner in the US properties. Previously, Brownstone controlled more than 10% of outstanding common shares of the Company. Effective September 28, 2011, Brownstone ceased to control more than 10% of outstanding common shares of the Company. Included in accounts receivable at December 31, 2011 is $Nil (December 31, 2010 - $168,771 and January 1, 2010 - $72,752) owing from Brownstone.

e) 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 December 31, 2011 is $Nil (December 31, 2010 - $967 and January 1, 2010 - $Nil) owing from HEC. Included in accounts payable and accrued liabilities at December 31, 2011 is $53,668 (December 31, 2010 - $166,139 and January 1, 2010 - $63,679) owing to HEC.

f) In January 2011, the remaining balance of loan from HEC was repaid in full in cash (see Note 9 to the consolidated financial statements for details).

g) 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 consolidated financial statements for details).

h) In December 2011, HEC exercised 250,000 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, have been 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 has not had 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 Note 3 and Note 25 to the Company's Consolidated Financial Statements for the year ended December 31, 2011. The reconciliations include the Consolidated Balance Sheets as at January 1, 2010 and December 31, 2010, Consolidated Statement of Changes in Shareholders' Equity for the year ended December 31, 2010, and Consolidated Statements of Comprehensive Loss for the year ended December 31, 2010.

The following provides a summary of the significant IFRS accounting policy changes.

Exploration and Evaluation Assets

Under previous GAAP, the Company followed the Canadian Institute of Chartered Accountants ("CICA") guideline on full cost accounting in which all costs directly associated with the acquisition of, the exploration for, and the development of natural gas and crude oil reserves are capitalized on a country-by-country cost centre basis. Costs accumulated within each country cost centre were depleted using the unit-of-production method based on proved reserves determined using estimated future prices and costs. Under IFRS, the Company is required to adopt new accounting policies for its oil and gas activities, including pre-exploration costs, exploration and evaluation costs and development costs.

Under IFRS, exploration and evaluation ("E&E") costs are those expenditures for an area or project for which technical feasibility and commercial viability have not yet been determined. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proven reserves are determined to exist. Development ("D&P") costs include those expenditures for areas or projects where technical feasibility and commercial viability have been determined. Under previous GAAP, all costs, including E&E assets were capitalized as Property and Equipment ("D&P"). Under IFRS, E&E costs and D&P are disclosed as different class of assets.

Impairment

Under previous GAAP, the Company was required to recognize an impairment loss if the carrying amount exceeds the undiscounted cash flows from proved reserves for the country cost centre. If an impairment loss was to be recognized, it was then measured as the amount that the carrying value exceeded the sum of the estimated fair value of the proved and probable reserves and the costs of unproved properties. Impairments recognized under previous GAAP could not be reversed.

Under IFRS, the Company is required to recognize and measure an impairment loss if the carrying value exceeds the recoverable amount for a cash-generating unit ("CGU"). Oil and gas assets are grouped into CGUs based on their ability to generate largely independent cash flows. Under IFRS, the recoverable amount is the higher of the estimated fair value less cost to sell and value in use. Impairment losses, other than goodwill, can be reversed when there is a subsequent increase in the recoverable amount.

Upon adoption of IFRS, the Company recognized an additional impairment charge of $14.7 million to the opening deficit at January 1, 2010, relating to certain non-core E&E assets in the US. The impairment charge was based on the difference between the net book value of the assets and the estimated recoverable amount. The recoverable amount was determined using the fair value less costs to sell based on the expected amount for which the asset could be sold in an arm's length transaction. Under previous GAAP, these assets were included in the US country cost centre ceiling test, which was not impaired as at December 31, 2009.

Warrant Liabilities

The Company issued US$ denominated warrants as part of equity financings, while the Company's functional currency is the CAD$. Under previous GAAP, common share purchase warrants were classified as equity.

Under IFRS, the Company determined that the warrants denominated in US$ outstanding at the date of transition must be treated as warrant liabilities in the Company's statement of financial position. Any issuance costs related to the warrants denominated in a foreign currency are expensed upon initial issuance. Prospectively, these warrants are re-measured at each balance sheet date based on estimated fair value, and any resultant changes in fair value are recorded as non-cash valuation adjustments as income or loss in the respective period.

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 December 31, 2011. 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 December 31, 2011 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 December 31, 2011, 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.

There were no changes in the Company's internal control over financial reporting that occurred during the three months ended December 31, 2011 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 net cash provided by operating activities before changes in non-cash operating working capital items.

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

Operating Loss is a non-GAAP measure defined as net income (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 income (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

bbl	barrel
bbls	barrels
BOP/D	barrels per day
Mbbls	thousand barrels
Mmbtu	million British thermal units

Natural Gas

Mcf	thousand cubic feet
MCFD	thousand cubic feet per day
MMcf	million cubic feet
MMcf/D	million cubic feet per day
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.