(formerly operating as Dejour Enterprises Ltd.)

MANAGEMENT DISCUSSION AND ANALYSIS

For the Nine Months Ended September 30, 2011

Date of Report: November 8, 2011

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, 2010 and the condensed interim unaudited consolidated financial statements for the nine months ended September 30, 2011 ("Interim Consolidated Financial Statements"). 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 interim 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 interim Consolidated Financial Statements for the nine months ended September 30, 2011.

All financial information in this MD&A is stated in Canadian dollars, the Company's reporting 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

The Company's business objective continues to be the achievement of sustainable growth through the investment in low risk development opportunities on current land holdings supplemented with potentially leveraging risk investments in new opportunities within North America. The rate at which the Company pursues opportunities is subject to commodity price fluctuations and thus the Company seeks opportunities like its liquids rich Gibson Gulch development (also called the Kokopelli field) located in Colorado, as a way to effectively generate positive returns while positioning the Company for a broad uplift in value as gas prices recover from current lows. The effective management of this sustainable growth program requires the Company to maintain a prudent but leveraging low debt to equity ratio, within the framework of minimal equity issuance. Management has designed the program to enhance long term shareholder value through the development of prudently assessed resource opportunities with careful management of exposure to adverse commodity price fluctuations.

Dejour's immediate plans remain focused on production growth from the Piceance Basin. The investments to be made in the Piceance during the upcoming years are economically attractive at current gas prices and expected to be highly leveraging for the Company as gas prices begin to recover from recent lows. During the third quarter, significant progress was made in the permitting and planning stages of our Piceance Basin properties. In particular, the first drilling permits for our project at Gibson Gulch were delivered in October 2011, thus allowing the Company to maintain its schedule for project startup in the fourth quarter of 2011 and production startup in the second half of 2012.

In addition to the focus on the Company's initial development project in the Piceance Basin, the Company continues to 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 developing its oil resources at Woodrush. As a result, the Company successfully completed the development and waterflood implementation of the Halfway "E" oil pool located in our Woodrush property. In June 2011, Dejour received a mid-year updated reserve evaluation report on its Woodrush oil pool valuing the PV-10 proved reserves at $25 million, with proved and probable reserves valued at $42 million net to Dejour's 75% W.I. The reserve evaluation bears an effective date of June 30, 2011 and was conducted by an independent firm, AJM Petroleum Consultants ("AJM") of Calgary, Alberta, a qualified reserve evaluator. In the second quarter of 2011, the Halfway "E" Pool began to show good response to the initial water injection as the producing gas oil ratio (GOR) dropped from 2,700 ft^3 per bbl to 250 ft^3 per bbl and the oil production rate began to increase. The Company's net production for the third quarter averaged 514 BOED (64% oil), a 81% increase over average production in the second quarter, despite the impact of scheduled summer maintenance on the gas transportation system that limited average gas production during the quarter to approximately 75% of field capacity.

Oil production from Woodrush is expected to continue to increase during the next twelve months. 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 will allow the Company to gradually increase production as water injection is increased and the producing GOR continues to decline. Project modifications designed to increase water injection by 50% are now underway with water injection up by 35% in October 2011 and additional increases scheduled for November 2011. In addition, the Company plans for an additional production well to be drilled, completed and producing from the Halfway "E" pool by the end of 2011.

In Colorado, Dejour drilled and cased an exploratory well at South Rangely in the 2nd quarter of 2011 targeting the oil potential in the Lower Mancos. The well was logged in June and a decision was taken to set casing on approximately 90 feet of potential pay in the Mancos C Sand. The well was scheduled to be fracture stimulated and tested in the third quarter of 2011. However, repositioning of fracture crews by the Company's service provider, driven by demand in the North Dakota and East Texas, resulted in an unexpected delay in executing the fracture treatment. Dejour is currently investigating options with all available service providers to fracture treat and test the well before the end of 2011.

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 119,000 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.

Q3 2011 HIGHLIGHTS

In Q3 2011, the Company's focus was on production optimization of the Drake/Woodrush property, while finalizing pre-drilling activities on its Gibson Gulch leases in the Piceance Basin.

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

1. Following the successful implementation of the Halfway "E" pool Waterflood on the Company's Woodrush property in the first quarter, oil production from the field continued increasing through the third quarter. Net production for the third quarter averaged 514 BOED (64% oil), a 81% increase over average production in the second quarter, despite the impact of scheduled summer maintenance on the gas transportation system that limited average gas production during the quarter to approximately 75% of field capacity.

2. In September 2011, the Company obtained a $7 million line of credit from a Canadian bank to refinance the bridge loan and to provide funds for general corporate purposes. The line of credit, repayable on demand by the bank, is at an interest rate of Prime + 1% (total 4% p.a. currently).

3. The Company generated positive operating cash flow for the current quarter.

4. In September 2011, 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 subsequent to the end of the third quarter.

SELECTED CONSOLIDATED FINANCIAL RESULTS

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
	$	$	$	$
Gross Revenues	2,947,000	2,534,000	6,347,000	6,557,000
Net Loss	(346,000)	(631,000)	(2,614,000)	(3,267,000)
Operating Cash Flow (1)	682,000	686,000	(72,000)	264,000
Operating Loss (1)	(48,000)	(511,000)	(2,042,000)	(2,894,000)

(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 on the conversion of resources into reserves. As a result of these moves, 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.

As at September 30, 2011, DEAL holds approximately 13,000 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 BOED (408 BOED net) in response to the decreasing pressure in the Halfway oil sand. Beginning the second quarter of 2011, water injection was gradually increased to a level of 1,500 BWPD. Beginning May 2011, the Halfway "E" Pool began to show response to the initial water injection as the producing gas oil ratio (GOR) dropped and the oil production rate began to increase. The Company's net production for the third quarter averaged 514 BOED (64% oil), a 81% increase over average production in the second quarter, despite the impact of scheduled summer maintenance on the gas transportation system that limited average gas production during the quarter to approximately 75% of field capacity.

While some additional development drilling will occur, the start-up 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.

US Activities

Gibson Gulch (Kokopelli Field – Piceance Basin)

The Company is working with its partners to bring this low risk development 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. Current plans call for the project to commence in the fourth quarter of 2011 with production expected to begin in the second half of 2012. In 2010, the Company was granted approval to develop a 660 acre portion of the Gibson Gulch leases with 10-acre spacing. Approval of this spacing on the remainder of the lease acreage would enable Dejour and its partner to drill up to 220 wells (158 wells net to Dejour) from a few multi-well drilling pads to optimally exploit the gas reserves in the subsurface.

South Rangely

Evaluation and subsequent exploitation of an oil prospect at the Company's South Rangely property, was deferred from the fourth quarter of 2010 to the second quarter of 2011, as a result of minor delays in the permitting process that prevented drilling from occurring before the winter drilling prohibitions designed to protect big game habitat. In June 2011, the Company drilled and cased an evaluation well on this 7,000 acre lease which is located just south of the Rangely field. The well is now waiting the scheduling of a fracture stimulation and subsequent production test. Successful drilling and production by an operator on offsetting acreage makes this project relatively low risk with the degree of economic success to be a function of the quality of the completion design. Success at South Rangely may allow the Company to revisit plans to evaluate and potentially exploit a 22,000 acre tract at the Company's North Rangely property. This acreage had previously been subject to farm-out with Laramie Energy II LLC. Due to market conditions, Laramie declined to follow through with the farm-out terms and the acreage has reverted to Dejour control. In the 2nd quarter of 2011, a well was drilled and casing set on approximately 90 feet of gross Mancos C sand at South Rangely. The well was scheduled to be fracture stimulated and tested in the third quarter of 2011. However, repositioning of fracture crews by the Company's service provider, driven by demand in the North Dakota and East Texas, resulted in an unexpected delay in executing the fracture treatment. Dejour is currently investigating options with all available service providers to fracture treat and test the well before the end of 2011.

West Grand Valley (Piceance Basin)

On the Company's West Grand Valley property, Dejour operates approximately 5100 gross acres with a 72% working interest in an area of active drilling by EnCana, Laramie Partners II and Axia. Here, 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 Gibson Gulch.

Future Exploration and Evaluation

Dejour retains a substantial amount of acreage prospective for oil and gas exploitation in other sections of the Colorado and Utah. Dejour owns approximately 109,000 net acres that was sculpted over the 2006-2008 period.

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

- Plateau (Piceance Basin) - This 4,500 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 22,000 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 slow recovery of natural gas prices has caused Dejour to delay the start of investments in Colorado. Exploitation of these opportunities will in all likelihood proceed once developments at Gibson Gulch, 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.

CAPITAL EXPENDITURES

Additions to property, plant and equipment and exploration and evaluation assets:

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
	$	$	$	$
Land acquisition and retention	84,431	73,647	204,713	241,452
Drilling and completion	326,598	(23,569)	2,544,331	1,093,270
Facility and pipelines	402,779	(37,658)	2,658,627	911,817
Capitalized general and administrative	260,260	239,177	574,369	1,143,468
Other assets	22,791	40,241	28,719	42,210
	1,096,859	291,838	6,010,759	3,432,217

DAILY PRODUCTION

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
By Product				
Natural gas (mcf/d)	1120	1,818	1,119	1,467
Oil and natural gas liquids (bbls/d)	327	307	217	265
Total (boe/d)	514	610	403	510

The decrease in natural gas production for both periods 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 oil production for the nine months ended September 30, 2011 compared to the same period in 2010 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. Oil production for the current quarter was 82% higher than in the second quarter of 2011.

SHARE CAPITAL

The following is a summary of share transactions for the nine months ended September 30, 2011 and the year ended December 31, 2010:

	Common Shares	$
Balance at January 1, 2010	95,791,038	**75,722,520**
- General share issuance costs	-	(130,593)
- Shares issued via private placements, net of issuance costs	14,389,507	4,114,101
- Flow through share liability	-	(407,975)
Balance at December 31, 2010	110,180,545	**79,298,053**
- Issue of shares on exercise of warrants	200,000	77,712
- Warrant liability reallocated on exercise of warrants	-	34,851
- Shares issued via private placements, net of issuance costs	11,010,000	2,693,813
- Warrant liability reclassified as equity	-	87,830
Balance at September 30, 2011	121,390,545	**82,192,259**

As at November 8, 2011, the Company had 121,390,545 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 cancelled (forfeited)	(200,000)	0.40
Options expired	(305,000)	0.45
Balance at September 30, 2011	9,654,000	0.38

Details of the outstanding and exercisable stock options as at September 30, 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	6,335,500	0.35	2.79	4,109,813	0.35	2.87
$0.45	3,318,500	0.45	2.39	1,851,350	0.45	2.35
	9,654,000	0.38	2.65	5,961,163	0.38	2.71

STOCK OPTIONS AND SHARE PURCHASE WARRANTS (continued)

As at September 30, 2011, 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, 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	(200,000)	0.42
Warrants expired	(3,491,090)	0.48
Balance at September 30, 2011	22,824,367	0.43

Details of the outstanding and exercisable warrants as at September 30, 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)
		$			$	
$0.38	140,359	0.38	0.23	140,359	0.38	0.23
$0.40	4,642,856	0.40	4.13	4,642,856	0.40	4.13
$0.55	4,015,151	0.55	2.73	4,015,151	0.55	2.73
$0.35 US	5,505,002	0.37	0.34	5,505,002	0.37	0.34
$0.40 US	7,875,000	0.42	3.23	7,875,000	0.42	3.23
$0.46 US	645,999	0.48	3.10	645,999	0.48	3.10
	22,824,367	0.43	2.61	22,824,367	0.43	2.61

SELECTED FINANCIAL HIGHLIGHTS

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

Operating Cash Flow

	Three months ended September 30, 2011	Three months ended September 30, 2010	Nine months ended September 30, 2011	Nine months ended September 30, 2010
	$	$	$	$
Cash from (used) in operating activities - GAAP	602,000	(160,000)	(691,000)	(278,000)
Less: changes in non-cash working capital	(80,000)	(846,000)	(619,000)	(542,000)
Operating Cash Flow – Non-GAAP	682,000	686,000	(72,000)	264,000

Operating Netback

	Three months ended September 30, 2011	Three months ended September 30, 2010	Nine months ended September 30, 2011	Nine months ended September 30, 2010
	$	$	$	$
Revenues	2,947,000	2,534,000	6,347,000	6,557,000
Less: Royalties	(614,000)	(362,000)	(1,199,000)	(1,133,000)
Less: Operating and transportation expenses	(664,000)	(544,000)	(1,642,000)	(2,050,000)
Operating Netback	1,669,000	1,628,000	3,506,000	3,374,000

Operating Loss

	Three months ended September 30, 2011	Three months ended September 30, 2010	Nine months ended September 30, 2011	Nine months ended September 30, 2010
	$	$	$	$
Net loss	(346,000)	(631,000)	(2,614,000)	(3,267,000)
Add back (losses) and deduct gains:				
Impairment losses	841,000	43,000	1,036,000	423,000
Change in fair value of warrant liability	(543,000)	77,000	(464,000)	(50,000)
Operating Loss	(48,000)	(511,000)	(2,042,000)	(2,894,000)

EBITDA

	Three months ended September 30, 2011	Three months ended September 30, 2010	Nine months ended September 30, 2011	Nine months ended September 30, 2010
	$	$	$	$
Net loss	(346,000)	(631,000)	(2,614,000)	(3,267,000)
Deferred income tax recovery	-	-	(187,000)	(271,000)
Finance costs	270,000	313,000	795,000	849,000
Amortization, depletion and impairment losses	1,417,000	1,039,000	2,633,000	3,129,000
EBITDA	1,341,000	721,000	627,000	440,000

Adjusted EBITDA

	Three months ended September 30, 2011	Three months ended September 30, 2010	Nine months ended September 30, 2011	Nine months ended September 30, 2010
	$	$	$	$
EBITDA	1,341,000	721,000	627,000	440,000
Adjustments:				
Non-cash stock-based compensation	150,000	170,000	549,000	632,000
Change in fair value of warrant liability	(543,000)	77,000	(464,000)	(50,000)
Adjusted EBITDA	948,000	968,000	712,000	1,022,000

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 SEPTEMBER 30, 2011 AND 2010

Summary of Operational Highlights

DEAL Production and Netback Summary

	Three Months Ended September 30, 2011	2010
Production Volumes:		
Oil and natural gas liquids (bbls)	30,101	28,233
Gas (mcf)	103,049	167,255
Total (BOE)	47,276	56,109
Average Price Received:		
Oil and natural gas liquids ($/bbls)	85.37	66.77
Gas ($/mcf)	3.66	3.81
Total ($/BOE)	62.34	45.16
Royalties ($/BOE)	12.98	6.44
Operating and Transportation Expenses ($/BOE)	14.04	9.68
Netbacks ($/BOE)*	35.31	29.04

*See Non-GAAP Measures

Revenues

	Three months ended September 30, 2011	2010
Revenue		
Gross revenues	**$ 2,947,000**	$ 2,534,000
Royalties	**(614,000)**	(361,000)
Revenues, net of royalties	**2,333,000**	2,173,000
Financial instrument gain	**-**	10,000
Other income	**9,000**	9,000
Total revenue	**$ 2,342,000**	$ 2,192,000

For the three months ended September 30, 2011 (“Q3 2011”), the Company recorded $2,947,000 in oil and natural gas sales as compared to $2,534,000 in oil and natural gas sales for the three months ended September 30, 2010 (“Q3 2010”). The increase in gross revenues was due to higher oil production for the current quarter. The decrease in natural gas production was primarily the result of the temporary curtailment of production due to maintenance related downtime at the regional gas processing plant in the 2^{nd} 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.

Despite lower gas production during Q3 2011, gross revenues increased by approximately 16% from Q3 2010 due to higher oil production and realized oil prices in the current quarter.

Royalties for Q3 2011 increased to $614,000 from $361,000 for Q3 2010. 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 September 30, 2011 and 2010:

	Three months ended September 30, 2011	2010
Dejour Realized Average Prices		
Natural gas ($/mcf)	$ 3.66	$ 3.81
Oil and natural gas liquids ($/bbl)	85.37	66.77
Total average price ($/boe)	$ 62.34	$ 45.16
Average Benchmark Prices		
Edmonton Par ($/bbl)	$ 92.45	$ 74.76
Natural gas - AECO-C Spot ($ per mcf)	$ 3.72	$ 3.72

Both the average natural gas sales prices and AECO-C daily spot prices for Q3 2011 were comparable to the prices received for Q3 2010. Oil prices received for Q3 2011 increased to $85.37 per barrel ("bbl"), compared to $66.77 per bbl for Q3 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 Q3 2011 increased to $664,000 from $544,000 for Q3 2010. In Q3 2010, the Company successfully recovered from a vendor a one-time reimbursement of previous operating expenses of approximately $130,000. Excluding this one-time reimbursement, the operating and transportation expenses for both quarters were comparable.

Change in Fair Value of Warrant Liability

The non-cash change in fair value of warrant liability for Q3 2011 was a gain of $543,000, compared to a loss of $77,000 for Q3 2010, 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.

Amortization, Depletion and Impairment Losses

For the current quarter, amortization, depletion and impairment losses were $1,417,000, compared to $1,039,000 for the same quarter in 2010. Amortization and depletion of property, plant and equipment for Q3 2011 was $576,000, compared to $996,000 for Q3 2010. The decrease in amortization and depletion expenses was mainly due to the increased reserves in the Woodrush property at the end of June 30, 2011 and the decrease in production. Impairment losses of $841,000 for Q3 2011, compared to $43,000 for Q3 2010, were recognized because the carrying value of a property, plant and equipment asset of $260,000 is not recoverable and certain leases for exploration and evaluation assets and property, plant and equipment of $581,000 were expired.

Net Loss and Operating Loss

The Company's net loss for the current quarter was $346,000 or $0.003 per share, compared to a net loss of $631,000 or $0.006 per share for the same quarter in 2010. The decrease in net loss was primarily due to higher revenues and the valuation gain from the decrease in fair value of warrant liability. This was partly offset by the increase in operating and transportation expenses and amortization, depletion and impairment losses.

The Company's operating loss for the current quarter was $48,000, compared to $511,000 for the same quarter in 2010. The decrease was primarily due to lower amortization and depletion of property, plant and equipment for the current quarter, as a result of the increased reserves in the Woodrush property.

EBITDA and Adjusted EBITDA

For the current quarter, EBITDA increased by $620,000 to $1,341,000 from $721,000 for Q3 2010. The increase was primarily due to the valuation gain from the decrease in fair value of warrant liability.

Adjusted EBITDA for the both quarters were comparable.

RESULTS OF OPERATIONS – NINE MONTHS ENDED SEPTEMBER 30, 2011 AND 2010

Summary of Operational Highlights

DEAL Production and Netback Summary

	Nine Months Ended September 30, 2011	2010
Production Volumes:		
Oil and natural gas liquids (bbls)	59,227	72,421
Gas (mcf)	305,567	400,401
Total (BOE)	110,155	139,154
Average Price Received:		
Oil and natural gas liquids ($/bbls)	87.47	66.76
Gas ($/mcf)	3.82	4.27
Total ($/BOE)	57.62	47.12
Royalties ($/BOE)	10.88	8.15
Operating and Transportation Expenses ($/BOE)	14.76	14.70
Netbacks ($/BOE)*	31.97	24.27

*See Non-GAAP Measures

Revenues

	Nine months ended September 30, 2011	2010
Revenue		
Gross revenues	**$ 6,347,000**	$ 6,557,000
Royalties	**(1,199,000)**	(1,133,000)
Revenues, net of royalties	**5,148,000**	5,424,000
Financial instrument gain (loss)	**(59,000)**	60,000
Other income	**26,000**	26,000
Total revenue	**$ 5,115,000**	$ 5,510,000

For the nine months ended September 30, 2011, the Company recorded $6,347,000 in oil and natural gas sales as compared to $6,557,000 in oil and natural gas sales for the nine months ended September 30, 2010. The reduction in gross revenues was due to lower oil and gas production for the first nine months of 2011 compared to the same period in 2010. This was partly offset by higher realized oil prices in 2011.

The following table summarizes the commodity prices realized by the Company and the crude oil and natural gas benchmark prices for the nine months ended September 30, 2011 and 2010:

	Nine months ended September 30,			
		2011		2010
Dejour Realized Average Prices				
Natural gas ($/mcf)	$	3.82	$	4.27
Oil and natural gas liquids ($/bbl)		87.47		66.76
Total average price ($/boe)	$	57.62	$	47.12
Average Benchmark Prices				
Edmonton Par ($/bbl)	$	94.32	$	76.84
Natural gas - AECO-C Spot ($ per mcf)	$	3.74	$	4.31

Both the average natural gas sales prices and AECO-C daily spot prices for the nine months ended September 30, 2011 were comparable to the prices received for the same period in 2010. Oil prices received for the nine months ended September 30, 2011 increased to $87.47 per barrel (“bbl”), compared to $66.76 per bbl for the same period in 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 the nine months ended September 30, 2011 decreased to $1,642,000 from $2,050,000 for the same period in 2010. The decrease was due to lower oil and gas production. Operating costs per BOE for both periods were comparable despite lower oil and gas production.

Change in Fair Value of Warrant Liability

The non-cash change in fair value of warrant liability for the nine months ended September 30, 2011 was a gain of $464,000, compared to a gain of $50,000 for the same period in 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 lower market prices for the Company’s common shares in the current quarter, this resulted in lower valuation for these warrants and a non-cash valuation gain for the nine months ended September 30, 2011.

Amortization, Depletion and Impairment Losses

For the nine months ended September 30, 2011, amortization, depletion and impairment losses were $2,633,000, compared to $3,129,000 for the same period in 2010. Amortization and depletion of property, plant and equipment for the first nine months of 2011 was $1,597,000, compared to $2,706,000 for the same period of 2010. The decrease in amortization and depletion expenses was mainly due to the increased reserves in the Woodrush property at the end of June 30, 2011 and the decrease in production. Impairment losses of $1,036,000 for the first nine months of 2011 were recognized because the carrying value of a property, plant and equipment asset of $260,000 is not recoverable and certain leases for exploration and evaluation assets and property, plant and equipment of $776,000 were expired, while the impairment losses of $63,000 and $360,000 for the same period of 2010 were recognized upon the expiry of certain leases for exploration and evaluation assets and property, plant and equipment, respectively.

Net Loss and Operating Loss

The Company's net loss for the nine months ended September 30, 2011 was $2,614,000 or $0.022 per share, compared to a net loss of $3,267,000 or $0.033 per share for the same period of 2010. The decrease in net loss was primarily due to lower operating and transportation expenses and amortization, depletion and impairment losses and the valuation gain from the decrease in fair value of warrant liability.

The Company's operating loss for the nine months ended September 30, 2011 was $2,042,000, compared to $2,894,000 for the same period in 2010. The decrease was primarily due to lower amortization and depletion of property, plant and equipment for the current period, as a result of the increased reserves in the Company's Woodrush property.

EBITDA and Adjusted EBITDA

For the nine months ended September 30, 2011, EBITDA increased by $187,000 to $627,000 from $440,000 for the same period in 2010. The increase was primarily due to higher valuation gain from the decrease in fair value of warrant liability.

For the nine months ended September 30, 2011, Adjusted EBITDA decreased by $310,000 to $712,000 from $1,022,000 for the same period in 2010. The decrease was primarily due to higher valuation gain from the decrease in fair value of warrant liability.

SUMMARY OF QUARTERLY RESULTS

The following summary for the eight most recently completed financial quarters ending September 30, 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.

	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 $	4th Quarter ended December 31, 2009 $
								(2009 Previous GAAP [1])
Gross Revenues	2,947,000	1,816,000	1,584,000	1,529,000	2,534,000	2,676,000	1,347,000	1,346,000
Net loss for the period	(346,000)	(189,000)	(2,079,000)	(2,078,000)	(410,000)	(52,000)	(2,584,000)	(7,049,000)
Basic and diluted net loss per common share	(0.003)	(0.002)	(0.018)	(0.020)	(0.004)	(0.001)	(0.026)	(0.082)

(1) As Dejour's IFRS transition date was January 1, 2010, the 2009 comparative information has not been restated.

The loss for the quarter ending December 31, 2009, when compared with the other quarters, was the result of the recognition of an impairment loss of resource properties of $5,360,000 in the quarter. Increased revenues in the current quarter reflected increased oil production due to the achievement of full allowable oil production level set by the OGC.

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 September 30, 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 Company had no commodity derivative contracts in place at September 30, 2011.

FINANCIAL CONDITION, LIQUIDITY AND CAPITAL RESOURCES

Cash Balance and Cash Flow

The Company had cash and cash equivalents of $512,000 as at September 30, 2011. In addition to the cash balance, the Company has an unused line of credit of $2.7 million from a Canadian Bank.

Bank Line of Credit Financing

In September 2011, the Company obtained a $7 million line of credit from a Canadian Bank to refinance the bridge loan of $4.1 million and to provide operating funds. The line of credit, repayable on demand by the bank, 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. As at September 30, 2011, a total of $4,307,828 of this facility was utilized.

According to the terms of the facility, DEAL is required to maintain a working capital ratio of not less 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 September 30, 2011, the Company is in compliance with the working capital ratio requirement of the bank.

Working Capital Position

As at September 30, 2011, the Company had a working capital deficit of $5,813,000. Excluding the non-cash warrant liability of $905,000 related to the fair value of US$ denominated warrants issued in previous equity financings, the working capital deficit mainly consisted of $4.3 million used demand line of credit. As at September 30, 2011, $2.7 million remains unused. 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 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, joint venture financing, or disposal of non-core assets.

Capital Resources

During the nine months ended September 30, 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 the first nine months of 2011. Further capital expenditures at Woodrush and US properties during the remainder of 2011 are expected to be approximately $2,000,000 and funded through its cash flow from operations and the undrawn line of credit.

In September 2011, the Company obtained a $7 million line of credit from a Canadian Bank to refinance the bridge loan and to provide operating funds for its capital expenditures. The line of credit, repayable on demand by the bank, is at an interest rate of Prime + 1% (total 4% p.a. currently). Its credit limit is based on the bank's interpretation of the Company's reserves and future commodity prices, subject to the bank's periodic review. The next review date is scheduled for December 1, 2011.

Also, the Company is pursuing debt or joint venture financing to fund its development at its Gibson Gulch property in the US.

Contractual Obligations

As of September 30, 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)	2011	2012	2013	2014	2015	Thereafter	Total
	$	$	$	$	$	$	$
Operating Lease Obligations	60	184	73	49	-	Nil	366
Bank line of credit	4,308	-	-	-	-	Nil	4,308
Total	4,368	184	73	49	-	Nil	4,674

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 September 30, 2011.

RELATED PARTY TRANSACTIONS

Except as disclosed elsewhere, during the nine months ended September 30, 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 and share based payments of $1,347,956 (2010 - $1,295,239). 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 September 30, 2011 is $Nil (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 - $211,171) in finance costs to a company controlled by an officer of the Company.

c) Included in interest and other income is $22,500 (2010 - $22,500) 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 September 30, 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 September 30, 2011 is $Nil (December 31, 2010 - $967 and January 1, 2010 - $Nil) owing from HEC. Included in accounts payable and accrued liabilities at September 30, 2011 is $10,694 (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 8 to the interim 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 12 to the interim consolidated financial statements for details).

These transactions are measured at the exchange amount established and agreed to by the related parties.

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 interim consolidated financial statements for the three and nine months ended September 30, 2011, including required comparative information, have been prepared in accordance with IFRS 1, *First-time Adoption of International Financial Reporting Standards*, and with International Accounting Standard ("IAS") 34, *Interim Financial Reporting*, as issued by the International Accounting Standards Board ("IASB"). 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 20 to the Company's Interim Consolidated Financial Statements for the three and nine months ended September 30, 2011. The reconciliations include the Consolidated Balance Sheets as at January 1, 2010, September 30, 2010 and December 31, 2010, Consolidated Statement of Changes in Shareholders' Equity for the nine and twelve months ended September 30, 2010 and December 31, 2010, respectively, and Consolidated Statements of Comprehensive Loss for the three and nine months ended September 30, 2010 and 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, Plant and Equipment (“PP&E”). Under IFRS, E&E costs and PP&E 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 September 30, 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 September 30, 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 September 30, 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 September 30, 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.