(formerly operating as Dejour Enterprises Ltd.)

MANAGEMENT DISCUSSION AND ANALYSIS

For the Year Ended December 31, 2010

Date of Report: March 29, 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 for the year ended December 31, 2010. On March 9, 2011, the Company changed its name from Dejour Enterprises Ltd. to Dejour Energy Inc.

All financial information in this Management's Discussion and Analysis ("MD&A") is expressed and prepared in accordance with the Canadian generally accepted accounting principles. All references are 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 remains the economic development of key projects and growth opportunities, resulting in the enhancement of shareholder value. This was accomplished in 2010 through prudent investment in and management of the Company's portfolio of producing and non-producing assets. As the business environment continues to improve we expect to accelerate prudent investment in our core assets and possibly a limited program of strategic acquisitions and divestitures when such activities allow us to enhance to our core assets and operations.

As 2010 began, oil prices had stabilized at a level of approximately US$80/barrel and many in the industry were projecting that the natural gas would strengthen throughout the year as the market returned to a supply demand balance reflecting the costs of shale gas developments. As 2010 progressed, natural gas prices sustained higher levels than they had achieved in 2009, but remained below early expectations as continuing advances in the drilling of new natural gas resource plays kept the market slightly oversupplied. While natural gas prices were disappointing, oil prices provided the industry a lift as they continued to strengthen throughout the year and surpassed $100/barrel in early 2011. Dejour tailored the 2010 development plan to allow the company to continue its growth despite the potential for this commodity price divergence driven by delay in the recovery of the natural gas prices. In 2010, all of Dejour's capital investments were targeted to developing our oil resources. As a result, we successfully completed the development of the Halfway oil pool located in our Woodrush property. At the same time, significant progress was made in the permitting and planning stages of our Piceance properties and in particular our project at Gibson Gulch, but capital commitments were delayed by six months and are now projected for the third and fourth quarter of 2011.

In Woodrush, Dejour's Proved plus Probable reserves for the field increased by 40% from 391 MBOE to 552 MBOE with 50% of the increase in oil. Gross production capacity from the field remains at approximately 1,260 BOED (800 BOD and 2.8 MMCFD), however current production is restricted by the British Columbia Oil and Gas Conservation Commission until the response from the water injection, commenced in March of 2011, is seen at the producing wells. Dejour commenced the waterflood project in October 2010 at a gross cost of approximately $4.4 million ($3.3 million net to Dejour). With the completion of the project in early 2011 all major capital investments in the field have been made and we anticipate production and revenue will now gradually increase until the field reaches its peak production capacity of 1,260 BOED in twelve to fifteen months.

In Colorado, Dejour still anticipates drilling one oil play and one gas play in 2011. A well at South Rangely will be drilled in the second quarter of 2011 to test the oil potential in the Lower Mancos. In the fourth quarter of 2011, a multi-well drilling program is projected to commence on Dejour's Gibson Gulch acreage where major Piceance operators Williams E&P and Bill Barrett Corp. have announced plans to increase drilling in 2011 on the properties surrounding Dejour's leasehold.

COMPANY OVERVIEW

The Company's 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 120,000 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

In Q2 2008, the Company commenced production and started receiving revenue from its Peace River Arch oil & gas properties, realizing the shift from a pure play exploration company to an exploration and production company.

2010 HIGHLIGHTS

In 2010, the Company's focus was on increasing production, reserves, and operational efficiency at the Drake/Woodrush properties, while maintaining all prospective acreage holdings and positioning for renewed drilling activities as both the business environment and commodity prices improved.

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

1. Extended the limits of the Woodrush halfway pool by drilling three successful development wells in 2010.

2. Received approval from the British Columbia Oil and Gas Commission to implement a waterflood in the Halfway oil pool at Woodrush and began project implementation in October.

3. Raised gross proceeds of $4.7 million in equity under challenging market conditions, allowing the Company to support the development of oil and gas properties in the Drake/Woodrush properties.

4. Obtained a bridge loan credit facility of up to $5 million, allowing the Company to refinance its existing bank facility and funds its working capital.

OIL AND GAS EXPLORATION AND PRODUCTION

During 2010 the Company further refined its focus toward on the conversion of resources into reserves. This process involved several distinct steps on the same continuum including:

- Classification and prioritization of acreage based on economic promise, technical robustness, infrastructural and logistic advantage and commercial maturity
- Evaluation and development planning for top tier acreage positions
- Developing partnerships within financial and industry circles to speed the exploitation process, and
- Aggressively bringing production on line where feasible.

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 modest risk exploration potential with a benign lease expiration profile.

US Activities

Gibson Gulch

The Company has moved forward aggressively to begin the process of bringing this low risk development project into production. Dejour's has a 72% working interest in this 2,200 acre project which is ideally situated for exploitation of thick columns 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 is working 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. After all permits are received, current plans call for drilling to commence in the fourth quarter of 2011 with production expected to begin later in that year or early 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 South Rangely, 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. Despite a minor delay, the Company has not altered its plans to drill an evaluation well on the 7,000 acre lease located just south of Rangely field. Recent advances in horizontal drilling and fracture stimulation technology have moved this previously marginal development into robust economic status. 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. 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.

West Grand Valley

In West Grand Valley, 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 this acreage is the 1400+ acre Roan Creek evaluation project. This opportunity 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 as 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 which provided the driving force for a single well drilling program. Permits have been applied for 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 Piceance and Uinta basins. Dejour has approximately 109,000 net acre position that was sculpted over the 2006-2008 period. Dejour is operator of approximately 130,000 acres and is a non-operator in another 110,000 acres where Retamco Operating Inc. and Fidelity Exploration and Production Company operate.

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 - This 4,500 acre (gross) project located south of Roan Creek in the Piceance Basin has significant Williams Fork potential as evidenced by successful drilling by EnCana Corporation at acreage adjacent to the Company's holdings.
- Greentown - This 15,000 acre (gross) prospect in the Uinta Basin in eastern Utah has significant oil potential as evidenced by drilling success encountered by Delta Petroleum in 2008. This area remains technically challenging due to issues associated with salt layers overlaying the target zone.
- North Rangely – This 22,000 acre (gross) project located north of the Rangely Field, is prospective for oil in the Lower Mancos (Niobrara) and Dakota formations

These potential developments will be deferred to at least 2012 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 only after developments at Gibson Gulch, South Rangely and Roan Creek reach equilibrium stage.

Summary of Capitalized US Oil and Gas Expenditures

A continuity summary of capitalized acquisition costs, exploration expenditures in the Company's US oil and gas properties for the year ended December 31, 2010 are as follows:

	2009	2010		
	Net Book Value	Expenditures (Dispositions), Net	Write-off	Net Book Value
US Oil and Gas Properties				
Colorado/Utah Projects				
Acquisition	$ 28,115,687	$ (415,416)	$ -	$ 27,700,271
Geological and geophysical	19,186	5,205	-	24,391
Capitalized general and administrative	313,577	553,953	-	867,530
	28,448,450	143,742	-	28,592,192
Others				
Acquisition	167,674	-	-	167,674
	167,674	-	-	167,674
Total US Oil and Gas Properties	**$ 28,616,124**	**$ 143,742**	**$ -**	**$ 28,759,866**

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.

For fiscal 2010, production from Dejour operated wells averaged about 640 BOE/D (100% gross), comprising of 320 BOPD of oil and natural gas liquids and 1,920 MCFD of gas, an increase of 7% over 2009 production. This was accomplished by successfully drilling two additional oil wells and one gas well during the year.

As at December 31, 2010, DEAL's holdings approximately 13,000 net acres concentrated in the Peace River Arch.

Production and Development Projects

Woodrush/Drake

After completing a 3-D seismic program over the field in January 2010, Dejour finalized drilling plans and in March commenced drilling of two development wells. The first found the target Halfway sand tight, but encountered a new Gething Gas pool that was subsequently put on production at more than 1,000 MCFD (100% gross). The second development well encountered the Halfway sand as expected, was completed and flow tested at rates in excess of 500 BOPD (100% gross). In October the first water injection well was drilled to the southeast limit of the reservoir. This well was produced briefly without the assistance of at 60 BOPD prior to conversion to injection.

With the success of the drilling in March 2010, field production reached a record level in May 2010, averaging 970 BOED (100% gross), where 75% is oil. In the fourth quarter of 2010, production from the field was reduced to approximately 560 BOED (100% gross) in response to increasing gas production resulting from the decreasing pressure in the Halfway oil sand. In December 2010, a waterflood project application was expedited and approval was received. The project was fully implemented in early 2011 with water injection commencing in March 2011. Water injection will be gradually ramped up to a level of 1,500 to 2,000 BWPD with the resulting oil production expected to reach a peak of approximately 900 BOPD (100% gross) in the second half of 2012.

While some additional development drilling is anticipated, the start-up of the waterflood marks the end of major capital investments in Woodrush. In 2011 Dejour will concentrate on optimizing injection and production in the waterflood, controlling cost and increasing margins on gas production as the oil production is gradually ramped up to its maximum level in the second half of 2012 when operating netback is expected to reach approximately $1.5 million per month.

Buick Creek (Montney Shale Basin)

In December 2010, the Company sold its entire 90% interest in this area for net proceeds of approximately $952,000.

Summary of Capitalized Canadian Oil and Gas Expenditures

A continuity summary of capitalized acquisition costs, exploration expenditures in the Company’s Canadian oil and gas properties for the year ended December 31, 2010 is as follows:

	December 31, 2009	December 31, 2010		
	Net Book Value	Expenditures (Dispositions), Net	Depletion	Net Book Value
Canadian Oil and Gas Properties				
Drake/Woodrush				
Land acquisition and retention	$ 386,110	$ 9,987	-	$ 396,097
Drilling and completion	5,283,495	2,237,991	-	7,521,486
Equipping and facilities	10,114,948	1,288,822	-	11,403,770
Geological and geophysical	454,956	644,141	-	1,099,097
Capitalized general and administrative	266,808	50,488	-	317,296
	16,506,317	4,231,429	-	20,737,746
Montney				
Land acquisition and retention	827,073	(827,073)	-	-
Capitalized interest	80,236	(80,236)	-	-
Capitalized general and administrative	8,473	(8,473)	-	-
	915,782	(915,782)	-	-
Saddle Hills				
Land acquisition and retention	4,948	672	-	5,620
Drilling and completion	887,902	1,632	-	889,534
Equipping and facilities	54,571	303	-	54,874
Geological and geophysical	78,407	1,650	-	80,057
Capitalized general and administrative	2,164	-		2,164
	1,027,992	4,257	-	1,032,249
Others				
Land acquisition and retention	1,623,177	16,619	-	1,639,796
Drilling and completion	4,420,145	(33,348)	-	4,386,797
Equipping and facilities	484,095	(45,509)	-	438,586
Geological and geophysical	952,530	-	-	952,530
Capitalized general and administrative	402,795	-	-	402,795
	7,882,742	(62,238)	-	7,820,504
Corporate Costs				
Assets retirement obligation	250,151	300,200	-	550,351
Depletion	(10,018,351)	-	(5,178,465)	(15,196,816)
Impairment	(3,955,854)	-	-	(3,955,854)
	(13,724,054)	300,200 -	(5,178,465) -	(18,602,319)
Total Canadian Oil and Gas Properties	**$ 12,608,779**	**$ 3,557,866**	**$ (5,178,465)**	**$ 10,988,180**

Summary of Net Capital Expenditures

The following table summarizes the breakdown of capital expenditures net of dispositions by type for the years ended December 31, 2010 and 2009 (excluding asset retirement obligation additions):

	December 31 2010	December 31 2009
Land acquisition and retention	$ (1,215,211)	$ 607,342
Drilling and completion	2,206,274	(2,642,906)
Equipping and facilities	1,243,616	(2,254,099)
Geological and geophysical	650,996	53,446
Capitalized general and administrative	595,968	359,991
Capitalized interest	(80,236)	10,919
Total net capital expenditures	$ 3,401,407	$ (3,865,307)

Daily Production

	December 31 2010	December 31 2009
By Product		
Natural gas (mcf/d)	**1,504**	1,524
Natural gas liquids (bbls/d)	**5**	4
Oil (bbls/d)	**231**	198
Total (boe/d)	**487**	456

Annual production for 2010 averaged 487 BOE/D, which is comparable to the annual production for 2009.

URANIUM EXPLORATION PROJECTS

During the year ended December 31, 2010, one of the leases expired. As a result, the Company recorded an impairment of uranium properties of $9,880 (2009: $148,906). The carrying value of the remaining 10% carried interest and 1% net smelter return was $523,205 as at December 31, 2010 and $533,085 as at December 31, 2009.

SELECTED ANNUAL INFORMATION

The following table set forth consolidated financial data prepared in accordance with Canadian GAAP for our last three fiscal years:

(in thousands of dollars except per share amounts)	For the Years Ended December 31		
	2010	2009	2008
	$	$	$
Revenues	8,154	6,786	5,766
Net loss	(5,165)	(12,807)	(20,891)
Loss per common share, basic and diluted	(0.05)	(0.16)	(0.29)
Total assets	46,355	45,886	62,643
Long-term obligation	-	2,345	1,950

The Company has not declared any cash dividends since inception.

SHARE CAPITAL

The following is a summary of share transactions for the years ended December 31, 2010 and 2009:

Authorized: Unlimited common voting shares
Unlimited first preferred shares, issuable in series
Unlimited second preferred shares, issuable in series

	Common Shares	Value
Balance at December 31, 2008	73,651,882	$ 64,939,177
- For cash on exercise of stock options	631,856	273,223
- For settlement of debt	8,030,303	2,650,000
- For cash by private placements, net of share issuance costs	13,476,997	4,549,882
- Contributed surplus reallocated on exercise of stock options	-	147,222
Balance at December 31, 2009	95,791,038	72,559,504
- General share issuance costs	-	(130,593)
- For cash by private placements, net of share issuance costs	14,389,507	4,114,101
- Renounced flow through share expenditures	-	(968,000)
Balance at December 31, 2010	110,180,545	$ 75,575,012

As at March 22, 2011, the Company had 121,390,545 issued and outstanding common shares.

STOCK OPTIONS AND SHARE PURCHASE WARRANTS

The following table summarizes information about stock option transactions:

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life
Balance, December 31, 2008	7,198,380	$ 1.22	2.94 years
Options granted	3,312,000	0.46	
Options exercised	(631,856)	0.43	
Options cancelled (forfeited)	(5,287,478)	1.45	
Options expired	(174,364)	1.72	
Balance, December 31, 2009	4,416,682	0.45	3.54 years
Options granted	3,573,000	0.35	
Options cancelled (forfeited)	(400,000)	0.39	
Options expired	(643,182)	0.46	
Balance, December 31, 2010	6,946,500	$ 0.40	3.47 years

Details of stock options vested and exercisable as at December 31, 2010 are as follows:

Number of Options Outstanding and vested	Exercise Price	Weighted Average Remaining Contractual Life (Years)
1,565,250	$ 0.35	4.12
1,684,825	$ 0.45	2.64
3,250,075	$ 0.40	3.35

As at December 31, 2010, no outstanding and vested options were “in the money” (the exercise price was more than the market trading price).

STOCK OPTIONS AND SHARE PURCHASE WARRANTS (continued)

The following table summarizes information about share purchase warrants:

	Outstanding Warrants		Weighted Average Exercise Price	Weighted Average Remaining Contractual Life
Balance, December 31, 2008	2,104,129	$	3.35	0.40 years
Warrants issued	14,736,150		0.47	
Warrants expired	(2,104,129)		3.35	
Balance, December 31, 2009	14,736,150		0.47	4.36 years
Warrants issued	6,274,305		0.41	
Balance, December 31, 2010	21,010,455	$	0.44	3.45 years

Details of warrants outstanding as at December 31, 2010 are as follows:

Number of Warrants Outstanding	Exercise Price	Weighted Average Remaining Contractual Life (Years)
140,359	$ 0.38	0.98
4,642,856	$ 0.40	4.88
1,491,090	$ 0.45	0.17
2,000,000	$ 0.50	0.47
4,015,151	$ 0.55	3.47
8,075,000	US$0.40	3.98
645,999	US$0.46	3.84
21,010,455		

SELECTED FINANCIAL HIGHLIGHTS

Operating Cash Flow

	For the three months ended December 31, 2010	2009	For the year ended December 31, 2010	2009
	$	$	$	$
Cash from (used) in operating activities - GAAP	1,106,000	(260,000)	396,000	(1,167,000)
Less: changes in non-cash working capital	1,512,000	237,000	533,000	(48,000)
Operating Cash Flow – Non-GAAP	(406,000)	(497,000)	(137,000)	(1,119,000)

Operating Cash Flow is a non-GAAP measure defined as net cash provided by operating activities before changes in assets and liabilities.

Operating Netback

	For the three months ended December 31, 2010	2009	For the year ended December 31, 2010	2009
	$	$	$	$
Revenues	1,536,000	1,346,000	8,154,000	6,786,000
Less: Royalties	(178,000)	(63,000)	(1,312,000)	(569,000)
Less: Operating and transportation expenses	(559,000)	(390,000)	(2,605,000)	(2,915,000)
Operating Netback	799,000	893,000	4,237,000	3,302,000

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

EBITDA

	For the three months ended December 31, 2010	2009	For the year ended December 31, 2010	2009
	$	$	$	$
Net loss	(1,451,000)	(7,049,000)	(5,165,000)	(12,807,000)
Future income tax recovery	(504,000)	-	(968,000)	(1,133,000)
Interest expense and finance fee	238,000	158,000	1,075,000	818,000
Amortization, depletion and accretion	1,357,000	904,000	5,250,000	6,437,000
EBITDA	(360,000)	(5,987,000)	192,000	(6,685,000)

EBITDA is a non-GAAP measure defined as net income (loss) before income tax expense, interest expense and finance fee, and amortization, depletion and accretion.

Adjusted EBITDA

	For the three months ended December 31, 2010	2009	For the year ended December 31, 2010	2009
	$	$	$	$
EBITDA	(360,000)	(5,987,000)	192,000	(6,685,000)
Adjustments:				
Non-cash stock-based compensation	156,000	198,000	620,000	697,000
Loss on disposition of investment in Titan	-	-	-	274,000
Equity loss from Titan	-	-	-	142,000
Impairment of uranium properties	-	34,000	10,000	149,000
Impairment of oil and gas properties	-	5,360,000	-	5,360,000
Adjusted EBITDA	(204,000)	(395,000)	822,000	(63,000)

Adjusted EBITDA is a non-GAAP measure and 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.

NON-GAAP MEASURES

Within the MD&A references are made to terms commonly used in the oil and gas industry.

Operating Cash Flow is a non-GAAP measure defined as net cash provided by operating activities before changes in assets and liabilities.

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

EBITDA is a non-GAAP measure defined as net income (loss) before income tax expense, interest expense and finance fee, and amortization, depletion and accretion.

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.

Certain measures in this document do not have any standardized meaning as prescribed by Canadian GAAP such as Operating Cash Flow, Operating Netback, 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.

SELECTED CONSOLIDATED FINANCIAL RESULTS

	For the three months ended December 31, 2010	2009	For the year ended December 31, 2010	2009
	$	$	$	$
Revenues	1,536,000	1,346,000	8,154,000	6,786,000
Net loss	1,451,000	7,049,000	5,165,000	12,807,000

RESULTS OF OPERATIONS – YEARS ENDED DECEMBER 31, 2010 AND 2009

Summary of Operational Highlights

DEAL Production and Netback Summary

	For the year ended December 31, 2010	2009
Production Volumes:		
Oil and natural gas liquids (bbls)	86,119	74,282
Gas (mcf)	548,890	566,158
Total (BOE)	177,599	166,353
Average Price Received:		
Oil and natural gas liquids (bbls)	67.46	54.63
Gas ($/mcf)	4.13	4.35
Total ($/BOE)	45.53	38.92
Royalties ($/BOE)	7.39	3.42
Operating and Transportation Expenses – compressor installation ($/BOE)	1.24	-
Other Operating and Transportation Expenses ($/BOE)	13.43	17.55
Total Operating and Transportation Expenses ($/BOE)	14.67	17.55
Netbacks ($/BOE)*	23.48	17.95

*See Non-GAAP Measures

Revenues

	For the year ended December 31, 2010	2009
Revenue		
Natural gas	**$ 2,265,000**	$ 2,413,000
Oil and natural gas liquids	**5,821,000**	4,058,000
Total oil and gas revenue	**8,086,000**	6,471,000
Realized financial instrument gain	**68,000**	315,000
Total revenue	**$ 8,154,000**	$ 6,786,000

For the year ended December 31, 2010 ("fiscal 2010"), the Company recorded $5,821,000 in crude oil and natural gas liquids sales and $2,265,000 in natural gas sales as compared to $4,058,000 in crude oil and natural gas liquids sales and $2,413,000 in natural gas sales for the year ended December 31, 2009 ("fiscal 2009"). The increase in revenues was due to the three new wells came on production in the current year. However, this was partly offset by the result of disposition of 100% interest in the Carson Creek and 25% interest in the Drake/Woodrush properties in 2009.

The following table summarizes the commodity prices realized by the Company and the crude oil and natural gas benchmark prices for the years ended December 31, 2010 and 2009:

	For the year ended December 31, 2010	2009
Dejour Average Prices		
Natural gas ($/mcf)	**$ 4.13**	$ 4.35
Oil and natural gas liquids ($/bbl)	**67.46**	54.63
Total average price ($/boe)	**$ 45.53**	$ 38.92
Average Benchmark Prices		
Western Canadian Select (WCS) ($/bbl)	**$ 67.25**	$ 58.69
Natural gas - AECO-C Spot ($ per mcf)	**$ 4.13**	$ 4.14

Both the average natural gas sales prices and AECO-C daily spot prices for fiscal 2010 were comparable to the prices received for the comparative year. Oil prices received for fiscal 2010 increased to $67.46 per barrel ("bbl"), compared to $54.63 per bbl for fiscal 2009. The increase was due to the gradual recovery of the global economic market, leading to higher commodity prices.

Royalties

	For the year ended December 31, 2010	2009
Royalties		
Crown	**$ 1,269,000**	$ 252,000
Freehold and GORR	**43,000**	317,000
Total royalties	**$ 1,312,000**	$ 569,000
$ per boe	**$ 7.39**	$ 3.42
As a percentage of oil and gas revenue	**16%**	9%

Royalties for fiscal 2010 increased 130% over the comparative year. The increase was mainly attributable to higher oil production for the current fiscal year, which is subject to higher royalty rate compared to the royalty rate for natural gas. During fiscal 2009, the British Columbia provincial government approved a royalty holiday for the first 72,000 barrels of oil production on one of the Company's oil wells. The Company received a royalty credit of $280,000 from the BC provincial government, resulting in a lower royalty for the year of 2009.

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 facility. The major components of operating expenses include labour, equipment maintenance, workovers, fuel and power. Operating and transportation expenses for fiscal 2010 decreased to $2,605,000 or $14.67 per BOE from $2,915,000 or $17.55 per BOE for fiscal 2009 despite higher revenues.

Operating costs on a per unit basis decreased compared to fiscal 2009, reflecting the addition of production from three new wells in Woodrush and the positive impact to the Company's operations as a result of the installation of the rental compressor, which lowered the ongoing compression costs and operating costs. The Company incurred approximately $220,000 for the installation in January 2010.

General and Administrative Expenses

General and administrative expenses decreased to $3,424,000 for fiscal 2010 from $4,038,000 for fiscal 2009. The decrease was primarily due to lower salaries and benefits, consulting and professional fees, and other general overhead for fiscal 2010 compared to fiscal 2009.

Interest Expense and Finance Fee

For fiscal 2010, the Company recorded interest expense and finance fee of $1,075,000, compared to $818,000 for fiscal 2009. The increase was due to the interest expense and finance fee associated with the utilization of the credit facility from a bridge loan lender since March 2010.

Stock Based Compensation

For fiscal 2010, the Company recorded non-cash stock based compensation expense of $620,000 compared to $697,000 for fiscal 2009. The decrease in stock based compensation expense was because many of the stock options previously granted had been fully vested.

Foreign Exchange Gain (Loss)

Foreign exchange gain for fiscal 2010 was decreased by $285,000 compared to fiscal 2009. At the end of 2008, the Company had a US dollar denominated loan of $3.8 million from a related party and recorded a foreign exchange gain of $257,000 for fiscal 2009 as a result of the lower US-Canadian exchange rate and the positive impact it had on the loan. In June 2009, the loan was converted into a Canadian dollar denominated loan and no foreign currency revaluation was necessary for the current year.

Impairment of Oil & Gas Properties

The impairment loss of oil and gas properties for fiscal 2010 is $Nil, compared to $5,360,000 for fiscal 2009. The Company recorded an impairment loss of $3,956,000 for the excess of the carrying value of Canadian oil and gas properties over its fair value as at December 31, 2009 based on an independent reserve evaluation report.
In addition, during fiscal 2009, the Company wrote off certain non-core acreages in the US that expired before determining proved reserves effective December 31, 2009 in March 2010 and recorded an impairment loss of $1,404,000.

Amortization, Depletion and Accretion

For fiscal 2010, amortization and depletion of property and equipment and accretion of asset retirement obligations was $5,250,000 compared to $6,437,000 for fiscal 2009. The decrease was due to the positive drilling results during the current year, which increased reserves in the Drake/Woodrush area at the end of December 31, 2010. This was partly offset by the increase in production.

Income Taxes

Future income tax recovery for fiscal 2010 was $968,000, as compared to future income tax recovery of $1,133,000 for fiscal 2009. The future income tax recovery for fiscal 2010 was a result of the Company's renunciation of $3,394,000 of Canadian Exploration Expenditures ("CEE") to investors in 2010. Under Canadian GAAP, the renunciation of CEEs results in future income tax liabilities and share issuance costs. The Company's previously unrecognized future income tax assets relating to loss carry forwards were offset against future income tax liabilities from the renunciation of CEEs, resulting in future income tax recoveries.

As at December 31, 2009, the Company had unrecognized future income tax assets relating to loss carry forwards and the excess of the value of the tax pools for the oil and gas properties over the accounting net book value, as compared to having a future income tax liability balance as at December 31, 2008, which resulted in future income tax recovery for fiscal 2009.

Net Loss

The Company's net loss for fiscal 2010 was $5,165,000 or $0.05 per share, compared to a net loss of $12,807,000, or $0.16 per share for fiscal 2009. The decrease in net loss was due to higher revenues and lower depletion expenses and general and administrative expenses. In addition, the decrease in net loss was attributable to no impairment of oil and gas properties recorded for the current year.

Operating Netback (See Non-GAAP Measures)

Operating netbacks for fiscal 2010 increased to $4,237,000 or $23.48 per BOE from $3,302,000 or $17.95 per BOE for fiscal 2009. The increase was mainly due to higher revenues and lower operating and transportation expenses. This was partly offset by increased royalties for the current year.

EBITDA and Adjusted EBITDA (See Non-GAAP Measures)

For fiscal 2010, EBITDA was $6,877,000 higher than fiscal 2009. It was primarily due to lower net loss for the current year. This was partly offset by lower depletion for the current year.

For fiscal 2010, Adjusted EBITDA was $885,000 higher than fiscal 2009. It was primarily due to higher EBITDA for the current year. This was partly offset by no impairment of oil and gas properties recorded for the current year.

RESULTS OF OPERATIONS – THREE MONTHS ENDED DECEMBER 31, 2010 AND 2009

Summary of Operational Highlights

DEAL Production and Netback Summary

	Three Months Ended December 31, 2010	2009
Production Volumes:		
Oil and natural gas liquids (bbls)	13,698	14,106
Gas (mcf)	148,489	89,082
Total (BOE)	38,445	28,842
Average Price Received:		
Oil and natural gas liquids ($/bbls)	71.17	64.07
Gas ($/mcf)	3.73	4.19
Total ($/BOE)	39.76	44.28
Royalties ($/BOE)	4.64	2.18
Operating and Transportation Expenses ($/BOE)	14.54	11.36
Netbacks ($/BOE)*	20.58	30.75

*See Non-GAAP Measures

Revenues

	Three months ended December 31, 2010	2009
Revenue		
Natural gas	**$ 554,000**	$ 431,000
Oil and natural gas liquids	**975,000**	909,000
Total oil and gas revenue	**1,529,000**	1,340,000
Realized financial instrument gain	**7,000**	6,000
Total revenue	**$ 1,536,000**	$ 1,346,000

For the three months ended December 31, 2010 ("Q4 2010"), the Company recorded $975,000 in crude oil and natural gas liquids sales and $554,000 in natural gas sales as compared to $909,000 in crude oil and natural gas liquids sales and $431,000 in natural gas sales for the three months ended December 31, 2009 ("Q4 2009"). The increase in revenues for Q4 2010 over Q4 2009 was due to higher oil and gas production for the current quarter.

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, 2010 and 2009:

	Three months ended December 31, 2010	2009
Dejour Average Prices		
Natural gas ($/mcf)	**$ 3.73**	$ 4.19
Oil and natural gas liquids ($/bbl)	**71.17**	64.07
Total average price ($/boe)	**$ 39.76**	$ 44.28
Average Benchmark Prices		
Western Canadian Select (WCS) ($/bbl)	**$ 67.90**	$ 67.69
Natural gas - AECO-C Spot ($ per mcf)	**$ 3.58**	$ 4.23

Both the average natural gas sales prices and AECO-C daily spot prices for fiscal 2010 were lower than the prices received for the comparative year. Oil prices received for Q4 2010 increased to $71.17 per barrel ("bbl"), compared to $64.07 per bbl for Q4 2009. The increase was due to the gradual recovery of the global economic market, leading to higher commodity prices.

Royalties

	Three months ended December 31, 2010	2009
Royalties		
Crown	**$ 168,000**	$ 34,000
Freehold and GORR	**10,000**	29,000
Total royalties	**$ 178,000**	$ 63,000
$ per boe	**$ 4.63**	$ 2.18
As a percentage of oil and gas revenue	**12%**	5%

The significant increase in royalties was because the British Columbia provincial government approved a royalty holiday for the first 72,000 barrels of oil production on one of the Company's oil wells in Q3 2009. The Company is not liable for royalties on oil production through Q4 2009, therefore resulting in a substantially lower royalty for the quarter.

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 2010 increased to $559,000 or $14.54 per BOE from $390,000 or $11.36 per BOE for Q4 2009. The increase was mainly due to higher maintenance and service costs associated with the new well commenced production in the current quarter.

General and Administrative Expenses

General and administrative expenses decreased to $998,000 for Q4 2010 from $1,203,000 for Q4 2009. The decrease was mainly due to lower salaries and benefits and consulting and professional fees for Q4 2010 compared to Q4 2009.

Interest Expense and Finance Fee

For the current quarter, the Company recorded interest expense and finance fee of $238,000, compared to $158,000 for Q4 2009. The increase was due to the interest expense and finance fee associated with the utilization of the bridge loan facility since March 2010.

Stock Based Compensation

For Q4 2010, the Company recorded non-cash stock based compensation expenses of $156,000, compared to $198,000 for Q4 2009. The decrease in stock based compensation expense was because many of the stock options previously granted had been fully vested.

Foreign Exchange Gain (Loss)

Foreign exchange loss was decreased by $115,000 to $16,000 for Q4 2010 from $131,000 for Q4 2009. Foreign exchange gain (loss) was attributable to the translation of foreign currency denominated net monetary assets into Canadian dollars at period end.

Impairment of Oil & Gas Properties

The impairment loss of oil and gas properties for Q4 2010 is $Nil, compared to $5,360,000 for Q4 2009. The Company recorded an impairment loss of $3,956,000 for the excess of the carrying value of Canadian oil and gas properties over its fair value as at December 31, 2009 based on an independent reserve evaluation report. The majority of the impairment loss relates to non-core assets that were abandoned or sold.

In addition, during fiscal 2009, the Company wrote off certain non-core acreages in the US that expired before determining proved reserves effective December 31, 2009 in March 2010 and recorded an impairment loss of $1,404,000.

Amortization, Depletion and Accretion

For the current quarter, amortization and depletion of property and equipment and accretion of asset retirement obligations was $1,357,000 compared to $904,000 for Q4 2009. The increase was due to the higher production for the current quarter.

Income Taxes

Future income tax recovery for Q4 2010 was $504,000, compared to $Nil for Q4 2009. The future income tax recovery for Q4 2010 was a result of the Company’s renunciation of $1,768,000 of Canadian Exploration Expenditures (“CEE”) to investors in the current quarter. Under Canadian GAAP, the renunciation of CEEs results in future income tax liabilities and share issuance costs. The Company’s previously unrecognized future income tax assets relating to loss carry forwards were offset against future income tax liabilities from the renunciation of CEEs, resulting in future income tax recoveries.

Net Loss

The Company's net loss for Q4 2010 was $1,451,000 or $0.01 per share, compared to a net loss of $7,049,000 or $0.08 per share for Q4 2009. The decrease in net loss was due to no impairment of oil and gas properties recognized for the current quarter.

Operating Netbacks (See Non-GAAP Measures)

Operating netbacks for the current quarter decreased to $799,000 or $20.58 per BOE from $893,000 or $30.75 per BOE for Q4 2009. The decrease was due to higher royalties and operating and transportation expenses. This was partly offset by higher revenues.

SUMMARY OF QUARTERLY RESULTS

The following summary for the eight most recently completed financial quarters ending December 31, 2010 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, 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 $	3rd Quarter ended September 30, 2009 $	2nd Quarter ended June 30, 2009 $	1st Quarter ended March 31, 2009 $
Revenues	1,536,000	2,544,000	2,768,000	1,305,000	1,346,000	1,056,000	1,682,000	2,702,000
Net loss for the period	(1,451,000)	(892,000)	(968,000)	(1,854,000)	(7,049,000)	(2,528,000)	(781,000)	(2,449,000)
Basic and diluted net loss per common share	(0.01)	(0.01)	(0.01)	(0.02)	(0.08)	(0.03)	(0.01)	(0.03)

Fluctuations in quarterly revenues and net loss over the last eight quarters are due primarily to the volatility in oil and natural gas prices and changes in sales volumes due to production growth through successful drilling activity, principally in the Drake/Woodrush area. Increased revenues in the middle two quarters of 2010 reflect increasing production due to successfully brought two new wells into production. The substantial 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 oil and gas properties of $5,360,000 in the quarter.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments consist of cash and cash equivalents, accounts receivable, bridge loan, accounts payable and accrued liabilities, and loans from related parties. 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 to joint venture partners and 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, 2010 and 2009, no accounts receivable has been deemed uncollectible or written off during the year.

(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 believes it has sufficient credit facilities to satisfy its financial obligations as they come due.

The Company's ongoing liquidity is impacted by various external events and conditions, including commodity price fluctuations and the global economic downturn.

(c) Commodity Price and Exchange Rate Volatility

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 actively manage the risks associated with price volatility and thereby protect its cash flows used to fund its capital program. The Company had no risk management contracts in place at December 31, 2010. For the year ended December 31, 2010, the Company recognized in income a realized gain of $67,923 on the risk management contracts in place during the year (2009 - $315,270).

The Company is also exposed to fluctuations in the exchange rate between the Canadian and U.S. dollar. Although substantially all of the Company's oil and natural gas sales are denominated in Canadian dollars, the underlying market prices in Canada for oil and natural gas are impacted by changes in the exchange rate between the Canadian and United States dollars. Given that changes in exchange rate have an indirect influence, the impact of changing exchange rates cannot be accurately quantified. The Company had no forward exchange rate contracts in place as at or during the year ended December 31, 2010 and 2009.

LIQUIDITY AND CAPITAL RESOURCES

Cash Balance and Cash Flow

The Company had cash and cash equivalents of $4,758,000 as at December 31, 2010. In addition to the cash balance, the Company also had accounts receivable of $689,000, most of which related to December 2010 oil and gas sales and had been received subsequent to December 31, 2010.

Our investing activities during the year ended December 31, 2010 were financed primarily by the proceeds raised from the issuance of flow-through shares and draw down of bridge loan during the year.

Bank Line of Credit and Bridge Loan Financing

During the year ended December 31, 2010, the bank line of credit of $850,000 was paid off in full in cash.

In March 2010, the Company negotiated a credit facility for a bridge loan of up to $5,000,000. This facility is secured by a first floating charge over all assets of DEAL, bears interest at 12% per annum and was due September 22, 2010 but was extended to March 31, 2011.

By agreement, certain terms of the facility were amended such that the credit limit is reduced by $100,000 per month and the Company is required to make monthly principal payments of $100,000 commencing November 30, 2010 with the borrowing subject to the drawdown fee adjusted to 2% from 1% on any amounts drawn and the deferred fee lowered to 1% from 2% on any repayments with no change in interest rate. Additionally, the due date of bridge loan is extended to March 31, 2011 and can be further extended for a maximum of 3 months subject to a 1% extension fee per month on the outstanding loan balance. In March 2011, the lender approved to extend the due date of the loan to April 30, 2011 and the Company is in discussion with the lender for further extension.

During the year ended December 31, 2010, the Company made monthly principal payment of $100,000 and reduced the outstanding balance to $4,800,000. This facility is used to support the development of its oil and gas properties in the Drake/Woodrush area.

According to the terms of the facility, the Company is required to maintain (a) a working capital ratio of not less than 1:1; (b) a debt to equity ratio within 0.5:1; and (c) a debt to trailing cash flow ratio within 2.5:1. The working capital ratio is defined as the ratio of (i) current assets (including any undrawn and authorized availability under the facility as cash) to (ii) current liabilities (excluding outstanding balances of the facility unless past due). The debt to equity ratio is defined as the ratio of (i) debt (secured debt plus working capital deficit or minus working capital surplus) to (ii) equity (shareholder equity plus retained earnings or minus deficit plus formally postponed shareholder and related party advances). The debt to trailing cash flow ratio is defined as the ratio of (i) debt (secured debt plus working capital deficit or minus working capital surplus) to (ii) cash flow (net income plus all non-cash charges). As at December 31, 2010, the Company is in compliance with all covenants.

Working Capital Position

As at December 31, 2010, the Company had a working capital deficit of to $1,984,000. The working capital deficit mainly consisted of loans from related parties and bridge loan drawn during the year ended December 31, 2010. The Company plans to remedy the deficiency through the following:

- Subsequent to December 31, 2010, the Company completed an equity financing of 11,010,000 units and raised net proceeds of approximately US$2.8 million.
- In December 2010, the Company obtained the approval for the implementation of a waterflood program at the Drake/Woodrush properties. In March 2011, the Company completed waterflood construction and commenced water injection. This waterflood is expected to increase the oil production gradually during the remainder of 2011.
- Once a new engineering evaluation is completed in the 2nd quarter of 2011, the Company intends to obtain a credit facility with a conventional bank to refinance the existing bridge loan. Subsequent to December 31, 2010, the Company had extended the due date of the loan to April 30, 2011 and continued discussion with the lender for further extension.
- If necessary and at the right market conditions, the Company may fund its working capital through additional debt, equity or disposal of non-core asset or a combination of both.

Capital Resources

Subsequent to December 31, 2010, the Company completed an equity financing of 11,010,000 units at US$0.30 per unit. Each unit consists of one common share and one-half of one common share purchase warrant. Each whole warrant entitles the holder to acquire one additional common share of the Company. Net proceeds raised were US$2.8 million.

In 2011, the Company plans to implement and optimize the waterflood at Drake/Woodrush in Canada. The Company's share of waterflood capital costs is approximately $2.5 million. Also, the Company plans to jointly operate with one of its working interest partners to acquire land and drill two horizontal development wells in Canada. Additionally, the Company intends to drill wells at Gibson Gulch and South Rangely in the US.

The Company plans to fund the development programs through a combination of debt, equity or joint ventures.

Contractual Obligations

As of December 31, 2010, 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	216	152	73	49	-	Nil	490
Bridge Loan	4,800	-	-	-	-	Nil	4,800
Loan from related party	250	-	-	-	-	Nil	250
Total	5,266	152	73	49	-	Nil	5,540

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, 2010.

RELATED PARTY TRANSACTIONS

Except as disclosed elsewhere, during the years ended December 31, 2010 and 2009, the Company entered into the following transactions with related parties:

a) The Company incurred a total of $520,152 (2009 - $682,618) in consulting and professional fees and a total of $Nil (2009 - $90,714) in rent expenses to the companies controlled by officers of the Company. The consulting and professional fees are included in general and administrative expenses. Included in accounts payable and accrued liabilities at December 31, 2010 is $12,000 (December 31, 2009 - $Nil) owing to a company controlled by an officer of the Company. Included in the total consulting and professional fees incurred during 2009 was $107,000 paid to a former officer of the Company to terminate the consulting agreement.

b) The Company incurred a total of $268,440 (2009 - $382,748) in interest expense and finance fee to the company controlled by an officer of the Company and Brownstone. Included in accounts payable and accrued liabilities at December 31, 2010 is $Nil (December 31, 2009 - $47,523) owing to the company controlled by an officer of the Company.

c) Included in interest and other income is $30,000 (2009 - $30,000) received from the companies controlled by officers of the Company for rental income.

d) Included in interest and other income is $Nil (2009 - $114,200) received from a public company which owns more than 10% of the Company's outstanding common shares ("Brownstone") for consulting services.

e) In July 2008, Brownstone became a 28.53% working interest partner in the US properties. Included in accounts receivable at December 31, 2010 is $169,687 (December 31, 2009 - $69,221) owing from Brownstone.

f) In December 2009, the company controlled by the CEO of the Company ("HEC") became a 5% working interest partner in the Drake/Woodrush properties. Included in accounts payable and accrued liabilities at December 31, 2010 is $166,139 (December 31, 2009 - $63,679) owing to HEC.

g) In December 2010, the Company sold its entire 90% working interest in the Buick Creek area to an unrelated third party for gross proceeds of approximately $952,000, in which HEC had a 10% working interest in the property.

h) In June 2009, HEC loan of $1.8 million to DEAL was assumed by the Company. Pursuant to the agreement entered between the Company and HEC in June 2009, as amended in September and December 2009, $450,000 of the debt was converted into 1,363,636 units consisting of 1,363,636 common shares and 681,818 common share purchase warrants exercisable at a price of $0.55 for a period of 5 years. The remaining $1,350,000 of outstanding debt was converted into a 12% note due on January 1, 2011. As a result of the sale of 5% working interest in the Drake/Woodrush area to HEC in December 2009 (effective June 1, 2009), both parties agreed to reduce the loan balance by the purchase price of $911,722 including taxes and adjustments. In addition, the loan balance was further reduced by a payment of $50,351. As at December 31, 2009, a balance of $387,927 remained outstanding. In December 2010, a repayment of $137,927 was made to HEC by the Company. As at December 31, 2010, a balance of $250,000 remained outstanding. Subsequent to December 31, 2010, the loan was repaid in full in cash (see Note 8 to the consolidated financial statements for details).

i) In June 2009, as amended in September and December 2009, the Company entered into an agreement with Brownstone in regard to the promissory note of $4,604,040 (US$3,780,000). Pursuant to the agreement, $2,200,000 (US$2,000,000) of the debt was converted into 6,666,667 units consisting of 6,666,667 common shares and 3,333,333 common share purchase warrants exercisable at a price of $0.55 for a period of 5 years. The remaining $2,070,140 (US$1,780,000) of the debt was converted into a Canadian dollar denominated 12% note due on January 1, 2011. The note is secured by the assets of Dejour Energy (USA) Corp. Also, the Company issued Brownstone 2,000,000 common share purchase warrants exercisable at $0.50 for a period of 2 years, with an issuer option to force the exercise of the warrants if the Company's common shares trade at a price of $0.80 or greater for 30 consecutive calendar days. As at December 31, 2009, a balance of $1,957,474 remained outstanding comprised of the loan balance of $2,070,140 minus unamortized portion of finance fees of $112,666. In December 2010, the loan was paid off in full in cash (see Note 8 to the consolidated financial statements for details).

j) With respect to the private placement of 2,907,334 flow-through units issued at $0.35 per unit completed in March 2010, directors and officers of the Company purchased 412,500 units of this offering (see Note 10 to the consolidated financial statements for details).

k) With respect to the private placement of 2,339,315 flow-through shares issued at $0.38 per share completed in December 2010, directors and officers of the Company purchased 513,157 units of this offering (see Note 10 to the consolidated financial statements for details).

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

SUBSEQUENT EVENTS

a) Stock Options

Subsequent to December 31, 2010, the Company granted a total of 3,562,500 incentive stock options with a weighted average exercise price at $0.35 per share to independent directors, management, officers, employees and consultants of the Company. The options can be exercised for periods ending up to March 15, 2014.

b) Private Placement

In February 2011, the Company completed a private placement of 11,010,000 units at US $0.30 per unit. Each unit consists of one common share and one-half of one common share purchase warrant. Each whole warrant entitles the holder to acquire one additional common share of the Company. The Company issued 5,505,000 share purchase warrants, exercisable at US$0.35 per warrant on or before February 10, 2012. Gross proceeds raised were US$3,303,000. In connection with this private placement, the Company paid finders' fees of US$199,710 in cash.

c) Derivative Financial Instruments

The Company uses commodity derivative financial instruments to manage its exposure to commodity price risk associated with the sale of its future crude oil and provide the Company with downside protection insurance on the decrease of commodity prices.

As at February 23, 2011, the Company had the following put options, allowing the Company the right, but not the obligation, to sell Western Texas Instrument ("WTI") crude oil:

Crude oil Contract	Contract Month	Volume	Price per barrel
WTI Crude oil put options	April 2011	6,000 barrels per month	US$93
WTI Crude oil put options	May 2011	6,000 barrels per month	US$93
WTI Crude oil put options	June 2011	6,000 barrels per month	US$93
WTI Crude oil put options	July 2011	6,000 barrels per month	US$93

d) Joint Venture Agreement

In February 2011, the Company entered into an exploration joint venture with a NYSE listed company ("US Oilco") related to certain of its Canadian landholdings. Terms of the joint venture include an option payment to the Company to a maximum of $1 million tied to its achievement of specific objectives in the first quarter of 2011.

Upon satisfactory achievement of the initial objectives, it is contemplated that the joint venture will fund land purchases of up to $5 million of any new lands, and in addition fund the drilling of two horizontal wells (combined US$9 million estimate). US Oilco will pay 65% of the costs to earn a 50% working interest on any new lands purchased and 80% of the drilling costs to earn a 50% working interest in the current lands. As contemplated by the agreement, the Company and US Oilco would continue to develop the project on an ongoing 50/50 basis beyond the earning period.

e) Loan from related party

Subsequent to December 31, 2010, the Company repaid the HEC loan in full in cash.

f) Change of Company Name

On March 9, 2011, the Company changed its name from Dejour Enterprises Ltd. to Dejour Energy Inc.

g) Bridge Loan

In March 2011, the lender approved to extend the due date of the loan to April 30, 2011 and the Company is in discussion with the lender for further extension.

CRITICAL ACCOUNTING ESTIMATES

There are a number of critical estimates underlying the accounting policies the Company applies in preparing its financial statements.

Reserves

The estimates of reserves is used in forecasting what will ultimately be recoverable from the properties and their economic viability and in calculating the Company's depletion and potential impairment of asset carrying costs. 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 at year end are evaluated by independent engineering firm and quarterly updates to those reserves, if any, are estimated by the Company.

Amortization, Depletion and Accretion

The Company estimates amortization, depletion and accretion that are based on estimates of oil and gas reserves that it expects to recover in the future.

Revenue and Cost Estimates

The Company estimates revenues, royalties and operating costs on production as at a specific reporting date, but for which actual revenues and costs have not yet been received.

Asset Retirement Obligations

The liability recorded for asset retirement obligations, an estimate of restoring assets and locations back to environmental and regulatory standards upon future retirement or abandonment, include estimates of restoration costs to be incurred in the future and an estimated future inflation rate. Costs estimated are based upon internal and third party calculations and historical experience and future inflation rates are estimated using historical experience and available economic data.

Income Taxes

The Company records future tax liabilities to account for the expected future tax consequences of events that have been recorded in its financial statements. These amounts are estimates; the actual tax consequences may differ from the estimates due to changing tax rates and regimes, as well as changing estimates of cash flow and capital expenditures in current and future periods. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded.

RECENTLY ADOPTED ACCOUNTING POLICIES AND FUTURE ACCOUNTING PRONOUNCEMENTS

Recently Adopted Accounting Policies

On January 1, 2010, the Company adopted the following Canadian Institute of Chartered Accountants (“CICA”) Handbook sections:

- Business Combinations, Section 1582, which replaces the previous business combinations standard. The standard requires assets and liabilities acquired in a business combination, contingent consideration and certain acquired contingencies to be measured at their fair values as of the date of acquisition. In addition, acquisition-related and restructuring costs are to be recognized separately from the business combination and included in the statement of earnings. The adoption of this standard will impact the accounting treatment of future business combinations entered into after January 1, 2010.

- Consolidated Financial Statements, Section 1601, which, together with Section 1602 below, replace the former consolidated financial statements standard. Section 1601 establishes the requirements for the preparation of consolidated financial statements. The adoption of this standard had no material impact on the Company’s consolidated financial statements.

- "Non-controlling Interests", Section 1602, which establishes the accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. The standard requires a non-controlling interest in a subsidiary to be classified as a separate component of equity. In addition, net earnings and components of other comprehensive income are attributed to both the parent and non-controlling interest. The adoption of this standard has had no material impact on the Company's consolidated financial statements.

Future Accounting Pronouncements

International Financial Reporting Standards ("IFRS")

In February 2008, the CICA Accounting Standards Board ("AcSB") confirmed the use of IFRS for publicly accountable profit-oriented enterprises beginning on January 1, 2011 with appropriate comparative data from the prior year. IFRS will replace GAAP for those enterprises, including listed companies and other profit-oriented enterprises that are responsible to large or diverse groups of stakeholders.

The Company commenced its IFRS project in 2009. This project consists of four phases: diagnostic; design and planning; solution development; and integration. The Company has completed the diagnostic phase, which involved a high-level review of the major differences between current GAAP and IFRS. The Company has determined that the areas of accounting differences with the highest potential impact to the Company are accounting for the exploration and evaluation of oil and gas resources, property, plant and equipment, and asset impairment testing, as well as accounting for stock-based compensation, derivative financial instruments, foreign currency translation and income taxes.

In 2010, the Company completed the design and planning phase of the project, which involves documenting the high impact areas identified and evaluating the different accounting policy options available under IFRS. During this phase, the Company also assessed the impact the changeover will have on current policies and procedures, information technology and accounting systems, as well as internal controls.

During the last quarter of 2010, the Company addressed the solution development phase, which involves the selection and documentation of IFRS accounting policies and procedures, as well as the development of accounting systems to enable the Company to track and report the financial information required to prepare financial statements under IFRS.

The Company is currently in the process of finalizing its January 1, 2010 opening balance sheet under IFRS and the IFRS comparatives for 2010 and has started to account for transactions in 2011 using IFRS accounting policies and procedures. The Company expects to be ready to report its first quarter 2011 results under IFRS.

The Company will continue to monitor the development of guidance on how to apply IFRS to oil and gas exploration and development activities, as well as the IFRS adoption efforts of its peers, and will update its plans as necessary.

Expected Accounting Policy Impacts

The Company's significant areas of impact continue to include property, plant and equipment ("PP&E"), impairment testing. These areas of impact have the greatest potential impact to the Company's financial statements. The following discussion provides an overview of these areas, as well as the exemptions available under IFRS 1, *First-time Adoption of International Financial Reporting Standards*. In general, IFRS 1 requires first time adopters to retrospectively apply IFRS, although it does provide optional and mandatory exemptions to these requirements.

Property, Plant and Equipment

Under Canadian GAAP, the Company follows the CICA's 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 are depleted using the unit-of-production method based on proved reserves determined using estimated future prices and costs. Upon transition to IFRS, the Company will be required to adopt new accounting policies for upstream activities, including pre-exploration costs, exploration and evaluation costs and development costs.

Pre-exploration costs are those expenditures incurred prior to obtaining the legal right to explore and must be expensed under IFRS. Currently, the Company capitalizes and depletes pre-exploration costs within the country cost centre. In 2009 and 2010, these costs were not material to the Company.

Exploration and evaluation costs are those expenditures for an area or project for which technical feasibility and commercial viability have not yet been determined. Under IFRS, the Company will initially capitalize these costs as Exploration and Evaluation assets on the balance sheet. When the area or project is determined to be technically feasible and commercially viable, the costs will be transferred to PP&E. Unrecoverable exploration and evaluation costs associated with an area or project will be expensed.

Development costs include those expenditures for areas or projects where technical feasibility and commercial viability have been determined. Under IFRS, the Company will continue to capitalize these costs within PP&E on the balance sheet. However, the costs will be depleted on a unit-of-production basis over an area level (unit of account) instead of the country cost centre level currently utilized under Canadian GAAP. The Company has not finalized the areas or the inputs to be utilized in the unit-of-production depletion calculation.

Under IFRS, upstream divestures will generally result in a gain or loss recognized in net earnings. Under Canadian GAAP, proceeds of divestitures are normally deducted from the full cost pool without recognition of a gain or loss unless the deduction would result in a change to the depletion rate of 20 percent or greater, in which case a gain or loss is recorded.

The Company expects to adopt the IFRS 1 exemption, which allows the Company to deem its January 1, 2010 IFRS upstream asset costs to be equal to its Canadian GAAP historical upstream net book value. On January 1, 2010, the IFRS exploration and evaluation costs are expected to be equal to the Canadian GAAP unproved properties balance and the IFRS development costs are expected to be equal to the full cost pool balance. The Company will allocate this upstream full cost pool over reserves to establish the area level depletion units.

Impairment

Under Canadian GAAP, the Company is required to recognize an upstream impairment loss if the carrying amount exceeds the undiscounted cash flows from proved reserves for the country cost centre. If an impairment loss is to be recognized, it is then measured at the amount the carrying value exceeds the sum of the fair value of the proved and probable reserves and the costs of unproved properties.

Under IFRS, the Company is required to recognize and measure an upstream impairment loss if the carrying value exceeds the recoverable amount for a cash-generating unit. Under IFRS, the recoverable amount is the higher of fair value less cost to sell and value in use. Impairment losses, other than goodwill, are reversed under IFRS when there is an increase in the recoverable amount. The Company will group its upstream assets into cash-generating units based on the independence of cash inflows from other assets or other groups of assets.

Stock-Based Compensation

Under IFRS, stock-based compensation is recognized based on a graded vesting schedule rather than the straight-line method utilized by the Company under Canadian GAAP. The difference calculated using the two methods for options that were not fully vested on the transition date must be recorded in retained earnings.

IFRS requires that each tranche of options is required to be treated as a separate award with a separate life. The Company expects to recognize an increase in the stock-based compensation expense in the vesting periods immediately following new grants. In addition, under IFRS, a forfeiture rate must be included in the initial expense calculation and adjusted prospectively if required, rather than accounting for forfeitures as they occur.

Derivative Financial Instruments

Under IFRS, derivative financial instruments are classified as equity or financial liabilities in accordance with their contractual substance. A financial instrument should be classified as either a financial liability or an equity instrument according to the substance of the contract, not its legal form, and the definitions of financial liability and equity instrument. The Company must decide at the time the instrument is initially recognized. The classification is not subsequently changed based on changed circumstances. An instrument is an equity instrument if, and only if, it satisfies the fixed-for-fixed test. If the instrument passes the test, it is accounted for as equity. If the instrument fails the test, it is a financial liability and will be accounted for at fair value through profit or loss.

Under Canadian GAAP, common share purchase warrants are classified as equity. It defines an equity instrument as any contract that evidences a residual interest in the assets of an entity after deducting all of its liabilities. There is no requirement under Canadian GAAP for the warrants to satisfy the fixed-for-fixed test.

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

Foreign Currency Translation

IFRS 1 allows companies to reset their existing cumulative translation account ("CTA") balances to zero at the date of transition. At present, the Company does not have any CTA balance. In addition, IFRS uses a hierarchy of indicators unlike Canadian GAAP to determine the functional currency. The functional currency of entities within the consolidated group could potentially be determined to be one other than the reporting currency which would result in the need for changes in the configuration of the consolidation systems. Under IFRS, a reporting currency other than the functional currency can be used in the reported financial statements. The Company has reviewed the functional currency assessment using the IFRS hierarchy and determined that the functional currency of its US subsidiary is not the same as the reporting currency of the Company. Therefore, the Company is required to translate the US subsidiary in line with the IFRS requirements retrospectively.

Income Taxes

Canadian GAAP and IFRS follow the liability method of accounting for income taxes, where tax assets and liabilities are recognized on temporary differences. However, there are certain exceptions to the treatment of temporary differences under IFRS that may result in an adjustment to the Company's future tax liability under IFRS. In addition, the Company's future tax liability will be affected by the tax effects of any changes noted in the above areas. The Company is still assessing the specific impacts of these differences on its financial statements.

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, 2010. 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, 2010 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, 2010, 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 Canadian GAAP.

The Chief Executive Officer and Chief Financial Officer of the Company have considered the Company's ICFR and identified that such controls did not operate effectively during the period with the result that misstatements were not prevented or detected in the interim financial statements for the six months ended June 30, 2010. Specifically, period end review of the interim financial statements by management did not identify the understatement of depletion on the oil and gas properties and the future income tax effects associated with the flow-through funds that were renounced to investors during the period. Such financial statements were subsequently restated and refiled. These restatements have no impact on the cashflow or cash position of the Company.

To remedy this weakness, the Company had improved staff training and period end review process. If necessary, the Company will engage external consultants to review complex accounting and financial reporting matters. With the change in operation of these controls, the Company believes that this type of situation will not occur.

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, 2010 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

Within the MD&A references are made to terms commonly used in the oil and gas industry.

Operating Cash Flow is a non-GAAP measure defined as net cash provided by operating activities before changes in assets and liabilities.

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

EBITDA is a non-GAAP measure defined as net income (loss) before income tax expense, interest expense and finance fee, and amortization, depletion and accretion.

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.

Certain measures in this document do not have any standardized meaning as prescribed by Canadian GAAP such as Operating Cash Flow, Operating Netback, 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.

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 which are not historical facts are forward-looking statements that involve risks, uncertainties and other factors that could cause actual results to differ materially from those expressed or implied by such forward looking statements. Factors that could cause such differences include, but not limited to, are volatility and sensitivity to market price for uranium, environmental and safety issues including increased regulatory burdens, possible change in political support for nuclear energy, changes in government regulations and policies, and significant changes in the supply-demand fundamentals for uranium that could negatively affect prices. Although the Company believes that the assumptions inherent in forward looking statements are reasonable we recommend that one should not rely heavily on these statements. The Company disclaims any intention or obligation to update or revise any forward looking statements whether as a result of new information, future events or otherwise.

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
BOPD	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.