DEJOUR ENTERPRISES LTD.
ENERGY. INDEPENDENCE.

MANAGEMENT DISCUSSION AND ANALYSIS

For the Six Months Ended June 30, 2010

(Restated January 20, 2011)

The following is an amended discussion of the consolidated operating results and financial position of Dejour Enterprises Ltd. (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, 2009 and the restated interim unaudited consolidated financial statements for the six months ended June 30, 2010.

All financial information in this amended Management's Discussion and Analysis ("MD&A") is expressed and prepared in accordance with the Canadian generally accepted accounting principles, except as disclosed. All references are in Canadian dollars, the Company's reporting currency, unless otherwise noted. Some numbers in this amended MD&A have been rounded to the nearest thousand for discussion purposes.

Certain forward-looking statements are discussed in this amended 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.

RESTATEMENT OF INTERIM FINANCIAL STATEMENTS

Subsequent to filing the interim financial statements for the six months ended June 30, 2010, management discovered an understatement of depletion on the oil and gas properties and unrecognized future income tax recovery related to the flow-through funds that were renounced to investors during the period. The Company has corrected these errors and has restated the interim financial statements for the six months then ended.

The net effect of the restatement on the interim financial statement for the six months ended June 30, 2010 is to decrease oil and gas properties by $1,027,000 and share capital by $464,000 and to increase the net loss, comprehensive loss and deficit by $563,000. The restatement is non-cash in nature and there is no impact on the operating cash flows, operating netback or EBITDA.

DEJOUR STRATEGY AND BUSINESS ENVIRONMENT

Dejour Enterprises Ltd. is an independent oil and natural gas company operating multiple exploration and production projects in North America's Piceance / Uinta Basin and Peace River Arch regions. In the first six months of 2010, Dejour was successful in doubling production at the Woodrush/Drake Field in N.E. British Columbia. This production increase was a key objective for Dejour for 2010. Also in the first half of 2010, oil prices strengthened and stabilized around the US$80/barrel level as gas price trended towards $5/MMBTU, allowing Dejour to post record revenues and achieve positive EBITDA in May and June of 2010. During this same period of expansion at Woodrush/Drake Field, the Company continued to move forward on the development of our key Piceance Basin acreage, where drilling is scheduled for 2011. Management believes that the Company's major Piceance projects are economical at US$80/barrel oil and US$5/Million BTU gas to attract competitive financing, allowing us to undertake important investments in the growth of the Company in 2010 and 2011 without significant dilution of the value of the projects.

As of June 30, 2010, the Company had increased its Proved and Probable reserves at Drake/Woodrush by slightly more than 100%, to 604,000 Barrels of Oil Equivalent (57% oil) from December 31, 2009, according to our independent reserve evaluator, GLJ Petroleum Consultants. Present Value (10%) of the Company's Proved and Probable reserves at Drake / Woodrush stood at $17 million as at June 30, 2010. A reserve and value increase for the Company resulting directly from the actions taken to preserve the company core assets in 2009.

For the balance of 2010, the Company anticipates an improving business environment and improving conditions in the financial markets. Dejour's growth over the next one to two years will come from exploiting development opportunities at Drake/Woodrush property and from the development of low risk, high value resource plays identified in select Piceance Basin properties.

Dejour's business objective remains the economic development of key projects and growth opportunities, resulting in the enhancement of shareholder value. This will be accomplished through prudent investment in and management of the Company's portfolio of producing and non producing assets, combined with a limited program of strategic acquisitions and divestitures in our core operating areas.

COMPANY OVERVIEW

Dejour shares trade on the Toronto Stock Exchange ("TSX") and the New York Stock Exchange AMEX ("NYSE-AMEX") under the symbol "DEJ".

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 and holds approximately 129,000 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, Dejour 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.

Q2 2010 HIGHLIGHTS

In the 2nd quarter of 2010, Dejour focused on increasing production 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 quarter, the Company achieved the following major corporate objectives and also made significant progress on key strategic initiatives that resulted in:

1. Successfully brought two new wells onto production, allowing the company to generate positive operating cash flow of $559,000 in Q2.

2. Increased Proved and Probable producing reserves at Drake / Woodrush to 534,000 Barrels of Oil Equivalent (58% oil), with a Present Value 10% (PV 10) at $15.7 million, an increase of 140% from December 31, 2009 PV 10 value of $6.5 million.

3. Average production increased to 599 BOE/D (58% oil) in Q2 2010, an 89% increase over Q1 2010.

4. Operating netback increased to $1.5 million in Q2 2010, a 416% improvement over Q1 2010.

5. In Q2 2010, EBITDA increased by $1.6 million delivering a positive EBITDA of $658,000, and yielded a positive Adjusted EBITDA of $808,000.

OIL AND GAS EXPLORATION AND PRODUCTION

In 2010, Dejour evolved its forward focus from acquiring resource potential toward 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

Dejour has moved forward aggressively to begin the process of bringing this low risk development project into production. The Company 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 Niobrara shale bodies. The Williams Companies, Inc. (NYSE: WMB) and Bill Barrett Corporation (NYSE: BBG) are developing and producing on adjacent acreage to the east, west and north of the Company's acreage. An independent reserve evaluator, Gustavson Associates, assigned 90 BCF in proven undeveloped reserves to Dejour's net acreage at Gibson Gulch as of December 31, 2009.

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 mid 2011 with production to begin later in that year. During Q1 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

Over 2009, Dejour developed a plan for evaluation and subsequent exploitation of an oil prospect at South Rangely. During 2010, the Company 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 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 with Dejour currently holding a 72% working interest of 22,000 acres in North Rangely.

Roan Creek

South and west of Gibson Gulch, Dejour owns 72% of the 1400+ acre Roan Creek evaluation project. This gas prone 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 pay in the Williams Fork at Roan Creek will be somewhat thinner than is found to the east, Roan Creek has potential for pay in the Mancos/Niobrara interval that 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 to be conducted in late 2010 or early 2011. Success at Roan Creek is expected to make some 3,000+ additional acres currently held by the Company prospective. This project is part of an emerging Niobrara exploration shale play.

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 with a 109,400 net acre position, sculpted over the 2006-2008 period. The Company 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 7,300 acre (gross) project located south of Roan Creek in the Piceance Basin has 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 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.

These potential developments will continue to be matured over 2010 with exploration or evaluation drilling scheduled for 2011/2012. Exploitation of these opportunities will in all likelihood proceed only after developments at Gibson Gulch, South Rangely and Roan Creek reach equilibrium stage.

Prospective acreage is located throughout the remainder of Dejour's land holdings. These positions, which were identified during studies conducted during 2008 and 2009, will be high graded over the years of 2010 to 2012 so that exploration and appraisal drilling programs can be developed for the middle part of the decade. If during further studies, certain acreage is deemed to have potential, it is possible for that acreage to leap the queue and assume a higher priority status than it currently enjoys.

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 six months ended June 30, 2010 are as follows:

	December 31, 2009	June 30, 2010		
	Net Book Value	**Net Expenditures**	**Write-off**	**Net Book Value**
US Oil and Gas Properties				
Colorado/Utah Projects				
Acquisition and lease rental	$ 28,115,687	$ 150,974	$ -	$ 28,266,661
Geological and geophysical	19,186	5,205	-	24,391
Capitalized general and administrative	313,577	232,453	-	546,030
	28,448,450	388,632	-	28,837,082
Others				
Acquisition	167,674	-	-	167,674
	167,674	-	-	167,674
Total US Oil and Gas Properties	**$ 28,616,124**	**$ 388,632**	**$ -**	**$ 29,004,756**

Canadian Activities

Dejour'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 June 30, 2010, DEAL's holdings totaled 20,247 net acres concentrated in the Peace River Arch and the Montney shale basin.

Production and Development Projects

Woodrush/Drake

After completing a comprehensive study of the Woodrush/Drake area in 2009, Dejour determined that the area presented room for value increase. Based on the recommendations of that study, the Company implemented a five point program that included:

- Operating cost reduction
- Production increase from existing wells
- Acquisition of additional prospective acreage
- Seismic data acquisition and analysis
- Step-out drilling from existing production based on seismic data.

In 2009, production from Dejour operated wells averaged about 456 BOE/D (202 BOPD of oil and natural gas liquids and 1,524 MCFD of gas). At December 31, 2009, gas production was limited due to restrictions imposed by a third party providing compression services. December 2009 production averaged 277 BOE/D (122 BOPD of oil and 930 MCFD of gas).

During the second half of 2009, DEAL made personnel and field management changes to reduce costs. Key to this program was the installation of a more cost effective gas compression system and the installation was completed in Q2 2010.

In January 2010, Dejour installed gas compression facilities which increased gas production capacity and lowered compression costs. In the second half of March, DEAL drilled, completed and tested two additional wells at Woodrush. The first well was productive in the Gething formation and tested at a rate in excess of gross 900 MCFD (net 675 MCFD) of natural gas. The second well was productive in the Halfway formation and tested at a rate in excess of gross 500 BOPD (net 375 BOPD) of oil. In May 2010, DEAL successfully brought these two wells into production.

In 2010 Q2, with the tie-in of an additional oil well, Dejour successfully increased its daily production to 599 BOE/D from 317 BOE/D in 2010 Q1 and increased the oil component of production to 58% oil from 41% in 2010 Q1. The Company was able to generate positive EBITDA of $658,000 and operating cash flow of $559,000 in 2010 Q2, an important milestone.

The Company conducted a 3-D seismic survey designed to investigate the northern portion of the Woodrush lease and the southern portion of the newly acquired acreage and identified at least two additional development locations, targeting half-way oil pool.

Dejour plans to drill these locations in the reminder of 2010. If the Company is successful in the remainder of 2010 drilling program, then it intends to implement a secondary recovery project to improve reserves and production.

Buick Creek (Montney Shale Basin)

DEAL acquired 6,352 gross and net acres in the emerging Montney natural gas resource play in northeastern British Columbia during 2008. In early 2009, Dejour also acquired an existing wellbore which the Company believes can be used for re-entry and testing of the play.

Saddle Hills

DEAL maintains a 25% working interest in 5,000 acres with two capped gas wells in the Saddle Hills area. The two wells are operated by Zargon Energy Trust, one of the Company's joint-venture partners. The recent announcement by the Alberta government on the lowering of oil and gas royalties will change the economics of the wells. We are waiting for details of the new royalty regime and will then discuss future development plan with Zargon.

DEJOUR ENTERPRISES LTD.
ENERGY INDEPENDENCE

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 six months ended June 30, 2010 is as follows:

	December 31, 2009	June 30, 2010		
	Net Book Value	**Expenditures (Dispositions), Net**	**Write-off / Depletion**	**Net Book Value**
Canadian Oil and Gas Properties				
Drake/Woodrush				
Land acquisition and retention	$ 386,110	$ 7,777	$ -	$ 393,887
Drilling and completion	5,283,495	1,161,793	-	6,445,288
Equipping and facilities	10,114,948	1,004,756	-	11,119,704
Geological and geophysical	454,956	614,494	-	1,069,450
Capitalized general and administrative	266,808	34,488	-	301,296
	16,506,317	2,823,308	-	19,329,625
Buick Creek (Montney)				
Land acquisition and retention	827,073	2,665	-	829,738
Capitalized interest	80,236	-	-	80,236
Capitalized general and administrative	8,473	20,415		28,888
	915,782	23,080	-	938,862
Saddle Hills				
Land acquisition and retention	4,948	403	-	5,351
Drilling and completion	887,902	478	-	888,380
Equipping and facilities	54,571	303	-	54,874
Geological and geophysical	78,407	-	-	78,407
Capitalized general and administrative	2,164	-		2,164
	1,027,992	1,184	-	1,029,176
Others				
Land acquisition and retention	1,623,177	7,398	-	1,630,575
Drilling and completion	4,420,145	(46,580)	-	4,373,565
Equipping and facilities	484,095	(55,584)	-	428,511
Geological and geophysical	952,530	-	-	952,530
Capitalized general and administrative	402,795	-	-	402,795
	7,882,742	(94,766)	-	7,787,976
Corporate Costs				
Assets retirement obligation	250,151	-	60,112	310,263
Depletion	(10,018,351)	-	(2,476,430)	(12,494,781)
Impairment	(3,955,854)	-	-	(3,955,854)
	(13,724,054)	-	(2,416,318)	(16,140,372)
Total Canadian Oil and Gas Properties	**$ 12,608,779**	**$ 2,752,806**	**$ (2,416,318)**	**$ 12,945,267**

The following table summarizes the breakdown of capital expenditures net of dispositions by type for the three and six months ended June 30, 2010 and 2009:

	Three Months Ended June 30 2010	Three Months Ended June 30 2009	Six Months Ended June 30 2010	Six Months Ended June 30 2009
Land acquisition and retention	$ 103,678	$ (1,055,789)	$ 169,217	$ (914,816)
Drilling and completion	7,585	(1,699,093)	1,115,691	(1,543,149)
Equipping and facilities	587,370	(1,515,973)	949,475	(1,416,242)
Geological and geophysical	520	11,331	619,699	27,463
Capitalized general and administrative	184,078	(144,081)	287,356	32,354
	$ 883,231	$ (4,403,605)	$ 3,141,438	$ (3,814,390)

Daily Production

	Three Months Ended June 30 2010	Three Months Ended June 30 2009	Six Months Ended June 30 2010	Six Months Ended June 30 2009
By Product				
Natural gas (mcf/d)	**1,500**	2,283	**1,288**	2,322
Natural gas liquids (bbls/d)	**3**	7	**5**	8
Oil (bbls/d)	**346**	166	**239**	262
Total (boe/d)	**599**	554	**459**	657

The production for the three months ended June 30, 2010 ("Q2 2010") averaged 599 BOE/D, an increase of 8% compared to the three months ended June 30, 2009 ("Q2 2009"). The increase was mainly due to the two new wells commenced production in May 2010. The production for the six months ended June 30, 2010 averaged 459 BOE/D, a decrease of 30% compared to the six months ended June 30, 2009. The decrease was the result of disposition of 100% interest in the Carson Creek area and 25% interest in the Woodrush/Drake properties in 2009. However, this was partly offset by production from the two successful wells which came on production in May 2010.

URANIUM EXPLORATION PROJECTS

As at June 30, 2010, the Company maintained a 10% carried interest and 1% Net Smelter Return on approximately 578,365 acres of uranium exploration claims and leases. During the six months ended June 30, 2010, there was no expiration of claims or leases. The carrying value of the Company's 10% carried interest and 1% Net Smelter Return was $533,085 as at June 30, 2010 and December 31, 2009.

SHARE CAPITAL

The following is a summary of share transactions for the six months ended June 30, 2010 and for the year ended December 31, 2009:

Authorized: Unlimited common 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
- Share issuance costs related to prior share offerings	-		(130,157)
- For cash by private placement, net of share issuance costs	2,907,334		910,173
- Renounced flow through share expenditures	-		(464,000)
Balance at June 30, 2010	98,698,372	$	72,875,520

As at August 11, 2010, the Company had 98,698,372 issued and outstanding common shares.

STOCK OPTIONS AND SHARE PURCHASE WARRANTS

The following table summarizes information about stock option transactions:

	Outstanding 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 and expired	(5,461,842)	1.46	
Balance, December 31, 2009	4,416,682	0.45	3.54 years
Options granted	3,323,000	0.35	
Options exercised	-	-	
Options cancelled and expired	(100,000)	0.45	
Balance, June 30, 2010	7,639,682	$ 0.41	3.67 years

Details of stock options vested and exercisable as at June 30, 2010 are as follows:

Number of Options Outstanding and vested	Exercise Price	Weighted Average Remaining Contractual Life (Years)
1,592,375	$ 0.45	2.61
120,000	$ 0.50	0.50
78,182	$ 0.55	0.50
872,000	$ 0.35	4.14
2,662,557	$ 0.42	2.96

As at June 30, 2010, no outstanding and vested options were “in the money” (the exercise price was less 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	1,491,090	0.45	
Balance, June 30, 2010	16,227,240	$ 0.47	3.57 years

Details of warrants outstanding as at June 30, 2010 are as follows:

Number of Warrants Outstanding	Exercise Price	Weighted Average Remaining Contractual Life (Years)
2,000,000	$ 0.50	0.98
4,015,151	$ 0.55	3.98
8,075,000	US$0.40	4.48
645,999	US$0.46	4.35
1,491,090	$ 0.45	0.67
16,227,240		

RELATED PARTY TRANSACTIONS

During the six months ended June 30, 2010 and 2009, the Company entered into the following transactions with related parties:

a) The Company incurred a total of $246,678 (2009 - $234,160) in consulting and professional fees and a total of $Nil (2009 - $69,013) in rent expenses to companies controlled by officers of the Company.

b) The Company incurred a total of $137,099 (2009 - $247,626) in interest expense and finance fee to related parties.

c) The Company received total rental income of $15,000 (2009 - $15,000) from companies controlled by officers of the Company.

d) The Company received total consulting fee income of $Nil (2009 - $114,200) from a related party which owns more than 10% of the Company's outstanding common shares.

These transactions are in the normal course of operations and are measured at the exchange amount established and agreed to by the related parties.

SELECTED FINANCIAL HIGHLIGHTS

Operating Cash Flow

	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
	$	$	$	$
Cash provided by (used in) operating activities – GAAP	552,000	(1,148,000)	-	(1,044,000)
Changes in non-cash working capital	(7,000)	(905,000)	419,000	(1,110,000)
Operating Cash Flow – Non-GAAP	559,000	(243,000)	(419,000)	66,000

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

Operating Netback

	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
	$	$	$	$
Revenues	2,675,000	1,682,000	4,023,000	4,095,000
Less: Royalties	(551,000)	23,000	(772,000)	(504,000)
Less: Operating and transportation expenses	(660,000)	(875,000)	(1,502,000)	(1,874,000)
Operating Netback	1,464,000	830,000	1,749,000	1,717,000

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

EBITDA

	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
	$	$	$	$
Net loss	(968,000)	(781,000)	(2,822,000)	(3,230,000)
Future income taxes recovery	-	(299,000)	(464,000)	(1,078,000)
Interest expense and finance fee	275,000	306,000	528,000	506,000
Amortization, depletion and accretion	1,351,000	1,264,000	2,500,000	3,975,000
EBITDA	658,000	490,000	(258,000)	173,000

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

	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
	$	$	$	$
EBITDA	658,000	490,000	(258,000)	173,000
Adjustments:				
Non-cash stock-based compensation	150,000	107,000	315,000	317,000
(Gain) loss on disposition of investment	-	(37,000)	-	274,000
Equity loss from Titan	-	-	-	142,000
Adjusted EBITDA	808,000	560,000	57,000	906,000

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.

NON-GAAP MEASURE

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

	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
	$	$	$	$
Revenues	2,768,000	1,682,000	4,073,000	4,384,000
Net loss	968,000	781,000	2,822,000	3,230,000

RESULTS OF OPERATIONS – THREE MONTHS ENDED JUNE 30, 2010 AND 2009

Summary of Operational Highlights

DEAL Production and Netback Summary

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009
Production Volumes:		
Oil and natural gas liquids (bbls)	31,753	15,777
Gas (mcf)	136,538	207,748
Total (BOE)	54,509	50,402
Average Price Received:		
Oil and natural gas liquids ($/bbls)	65.79	59.43
Gas ($/mcf)	4.29	3.88
Total ($/BOE)	49.08	34.61
Royalties ($/BOE)	10.11	(0.45)
Operating Expenses ($/BOE)	12.11	18.60
Netbacks ($/BOE)	26.87	16.45

Revenues

		Three Months Ended June 30, 2010		Three Months Ended June 30, 2009
Revenue				
Natural gas	**$**	**586,000**	$	744,000
Oil and natural gas liquids		**2,089,000**		938,000
Total oil and gas revenue		**2,675,000**		1,682,000
Realized financial instrument gain		**93,000**		-
Total revenue	**$**	**2,768,000**	$	1,682,000

For Q2 2010, the Company recorded $2,089,000 in crude oil and natural gas liquids sales and $586,000 in natural gas sales as compared to $938,000 in crude oil and natural gas liquids sales and $744,000 in natural gas sales for Q2 2009. The increase in revenues was mainly attributable to the result of the two new wells commenced production in May 2010.

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 June 30, 2010 and 2009:

		Three Months Ended June 30, 2010		Three Months Ended June 30, 2009
Dejour Average Prices				
Natural gas ($/mcf)	**$**	**4.29**	$	3.88
Oil ($/bbl)		**65.33**		59.88
Total average price ($/boe)	**$**	**49.08**	$	34.61
Average Benchmark Prices				
Western Canadian Select (WCS) ($/bbl)	**$**	**65.63**	$	60.66
Natural gas - AECO-C Spot ($/mcf)	**$**	**3.86**	$	3.62

Both the average natural gas sales prices and AECO-C daily spot prices for Q2 2010 were comparable to the prices received for Q2 2009. Oil prices received for Q2 2010 increased to $65.33 per barrel ("bbl"), compared to $59.88 per bbl for Q2 2009. The increase was due to the gradual recovery of the global economic market; leading to higher commodity prices.

Royalties

		Three Months Ended June 30, 2010		Three Months Ended June 30, 2009
Royalties				
Crown	**$**	**540,000**	$	(126,000)
Freehold and GORR		**11,000**		103,000
Total royalties	**$**	**551,000**	$	(23,000)
$ per boe	**$**	**10.11**	$	(0.45)
As a percentage of oil and gas revenue		**21%**		-1%

Royalties for Q2 2010 increased substantially over Q2 2009 consistent with higher revenues generated. In Q2 2009, the British Columbia government approved a royalty holiday for the first 72,000 barrels of oil production on one of the Company's oil well. The Company received a royalty credit of $280,000 from the BC provincial government, resulting in a net royalty recovery for the quarter. This 72,000 barrels royalty holiday was used up in 2009 and the Company is subject to a regular royalty rate 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 and rental, workovers, fuel and power. Operating and transportation expenses for Q2 2010 decreased to $660,000 or $12.11 per BOE from $875,000 or $18.60 per BOE for Q2 2009 despite higher revenues. The installation of the compressor in January 2010 resulted in minimal compression costs, which accounted for the reduction in operating and transportation expenses for the current quarter.

Operating Netbacks

Operating netbacks for the current quarter increased to $1,464,000 or $26.87 per BOE from $830,000 or $16.45 per BOE for Q2 2009. The increase was mainly due to higher revenues and lower operating and transportation expenses. This was partially offset by increased royalties for Q2 2010.

General and Administrative Expenses

General and administrative expenses decreased to $769,000 for Q2 2010 from $852,000 for Q2 2009. The decrease was primarily due to the lower professional fees and other general overhead for the current quarter compared to the same period in 2009.

Interest and Finance Fees

For Q2 2010, the Company recorded interest and finance fees of $275,000, compared to $306,000 for Q2 2009. The decrease was mainly the result of the revolving operating loan facility paid off in March 2010. However, this was partly offset by the loan fees for setting up a credit facility of up to $5 million with Toscana Capital Corporation in March 2010 and the interest expenses associated with the utilization of the facility and the fees related to the search for future financings.

Amortization, Depletion and Accretion

For Q2 2010, amortization and depletion of property and equipment and accretion of asset retirement obligations was $1,351,000 compared to $1,264,000 for Q2 2009. The increase was due to the higher production for the current quarter compared to the same period in 2009.

Stock Based Compensation

For Q2 2010, the Company recorded non-cash stock based compensation expense of $150,000 compared to $107,000 for Q2 2009. The increase was mainly attributable to the initial grant of stock options during the six months ended June 30, 2010.

Income Taxes, Foreign Exchange Gain and Other Items

Future income tax recovery for Q2 2010 was $Nil, as compared to future income tax recovery of $299,000 for Q2 2009. As at June 30, 2010, the Company did not have recognized future income tax assets associated with the potential income tax benefits because their realization is uncertain. Therefore, no future income tax recovery is recorded for the current quarter. The balance of future income tax liability as at June 30, 2009, which arose because the accounting net book value assigned to the oil and gas properties was in excess of the value of the tax pools, was lower than the balance as at March 31, 2009, resulting in future income tax recovery for Q2 2009.

Foreign exchange gain was decreased by $464,000 to $13,000 for Q2 2010 from $477,000 for Q2 2009. At the end of Q2 2009, the Company had a US dollar denominated loan of $3.8 million from a related party and recorded a foreign exchange gain in Q2 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 in Q2 2010.

The decrease in interest and other income was because no management fee income was received from a related party in Q2 2010. In Q2 2009, management fee income was received for financial advisory and project management services provided to the related party.

Net Loss

The Company's net loss for Q2 2010 was $968,000 or $0.01 per share, compared to a net loss of $781,000, or $0.01 per share for Q2 2009. The increase in net loss was mostly attributable to increased royalties and decreased foreign exchange gain, partially offset by increased revenues and decreased operating and transportation expenses.

Operating Cash Flow

The Company generated a positive operating cash flow of $559,000 for Q2 2010 compared to a negative operating cash flow of $243,000 for Q2 2009. It was primarily the result of the two new wells commenced production in May 2010.

EBITDA and Adjusted EBITDA

EBITDA for Q2 2010 increased to $658,000 from $490,000 for Q2 2009. The increase was mainly attributable to in the Q2 2009, the add-back of future income tax recovery of $299,000.

Adjusted EBITDA for Q2 2010 increased to $808,000 from $560,000 for Q2 2009. The increase was primarily attributable to higher EBITDA and stock-based compensation expenses.

RESULTS OF OPERATIONS – SIX MONTHS ENDED JUNE 30, 2010 AND 2009

Summary of Operational Highlights

DEAL Production and Netback Summary

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Production Volumes:		
Oil and natural gas liquids (bbls)	44,188	48,902
Gas (mcf)	233,146	420,347
Total (BOE)	83,045	118,961
Average Price Received:		
Oil and natural gas liquids ($/bbls)	66.75	47.67
Gas ($/mcf)	4.60	4.34
Total ($/BOE)	48.44	34.94
Royalties ($/BOE)	9.30	4.24
Operating Expenses – compressor installation ($/BOE)	2.65	-
Other Operating Expenses ($/BOE)	15.44	16.86
Total Operating Expenses ($/BOE)	18.09	16.86
Netbacks ($/BOE)	21.06	14.44

Revenues

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Revenue		
Natural gas	**$ 1,073,000**	$ 1,763,000
Oil and nautral gas liquids	**2,950,000**	2,331,000
Total oil and gas revenue	**4,023,000**	4,094,000
Realized financial instrument gain	**50,000**	290,000
Total revenue	**$ 4,073,000**	$ 4,384,000

For the six months ended June 30, 2010, the Company recorded $2,950,000 in crude oil and natural gas liquids sales and $1,073,000 in natural gas sales as compared to $2,331,000 in crude oil and natural gas liquids sales and $1,763,000 in natural gas sales for the six months ended June 30, 2009. The decrease in revenues was mainly the result of disposition of 100% interest in the Carson Creek area and 25% interest in the Woodrush/Drake properties in 2009. This was partly offset by production from the two new wells which tied into production in May 2010.

The following table summarizes the commodity prices realized by the Company and the crude oil and natural gas benchmark prices for the six months ended June 30, 2010 and 2009:

		Six Months Ended June 30, 2010		Six Months Ended June 30, 2009
Dejour Average Prices				
Natural gas ($/mcf)	**$**	**4.60**	$	4.34
Oil ($/bbl)		**67.04**		47.72
Total average price ($/boe)	**$**	**48.44**	$	34.94
Average Benchmark Prices				
Western Canadian Select (WCS) ($/bbl)	**$**	**69.08**	$	51.64
Natural gas - AECO-C Spot ($ per mcf)	**$**	**4.61**	$	4.27

Both the average natural gas sales prices and AECO-C daily spot prices for the six months ended June 30, 2010 were comparable to the prices received for the same period in 2009. Oil prices received for the six months ended June 30, 2010 increased to $67.04 per barrel ("bbl"), compared to $47.72 per bbl for the same period in 2009. The increase was due to the gradual recovery of the global economic market; leading to higher commodity prices.

Royalties

		Six Months Ended June 30, 2010		Six Months Ended June 30, 2009
Royalties				
Crown	**$**	**738,000**	$	227,000
Freehold and GORR		**34,000**		277,000
Total royalties	**$**	**772,000**	$	504,000
$ per boe	**$**	**9.30**	$	4.24
As a percentage of oil and gas revenue		**19%**		12%

Royalties for the six months ended June 30, 2010 increased 40% over the same period in 2009 despite lower revenues. In Q2 2009, the British Columbia government approved a royalty holiday for the first 72,000 barrels of oil production on one of the Company's oil well. The Company received a royalty credit of $280,000 from the BC provincial government, resulting in a low royalty rate in the first six months of 2009. This 72,000 barrels royalty holiday was used up in 2009 and the Company is subject to a regular royalty rate 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 and rental, workovers, fuel and power. Operating and transportation expenses for the six months ended June 30, 2010 were $1,502,000 or $18.09 per BOE as compared to $1,874,000 or $16.86 per BOE for the six months ended June 30, 2009. On a per BOE basis, operating and transportation expenses are higher than the same period in the prior year for the following reasons:

- In January 2010, the Company incurred approximately net $220,000 for the installation of a rental compressor in the Woodrush field, resulting in higher per unit costs for the six months ended June 30, 2010, compared to the same period in 2009.

- Delays in completing the installation of the compressor and other operational disruptions during the installation process resulted in the curtailed gas production in the first half of 1st quarter of 2010. As the majority of the operating expenses are fixed costs, therefore they are spread over a lower production base, resulting in higher per unit costs for the six months ended June 30, 2010.

Excluding the non-recurring installation cost of the compressor and the production delays and shut-in, the operating costs per BOE for the six months ended June 30, 2010 would have been lower compared to the same period in 2009. This reflects the positive impact to the Company's operations as a result of the installation of the compressor, which had increased the gas production and lowered the ongoing compression costs and operating costs.

Operating Netbacks

Operating netbacks for the six months ended June 30, 2010 were $1,749,000 or $21.06 per BOE as compared to $1,717,000 or $14.44 per BOE for the same period in 2009. The netbacks were impaired by $2.65 per BOE being the costs associated with the installation of the compressor. Excluding these non-recurring costs, the resultant netbacks for the six months ended June 30, 2010 were actually $23.71 per BOE, a 64% improvement over the same period in the prior year.

General and Administrative Expenses

General and administrative expenses for the six months ended June 30, 2010 were consistent with the same period in 2009.

Interest and Finance Fees

Interest and finance fees for the six months ended June 30, 2010 were consistent with the same period in 2009.

Amortization, Depletion and Accretion

For the six months ended June 30, 2010, amortization and depletion of property and equipment and accretion of asset retirement obligations was $2,500,000 compared to $3,975,000 for the six months ended June 30, 2009. The decrease was due to the positive drilling results in Mar 2010, which increased reserves in the Drake/Woodrush area at the end of June 30, 2010. Also, the lower production for the six months ended June 30, 2010 compared to the same period in 2009 contributed to the decrease in depletion.

Stock Based Compensation

Non-cash stock based compensation expense recorded for the six months ended June 30, 2010 was consistent with the same period in 2009.

Income Taxes, Foreign Exchange Loss and Other Items

Future income tax recovery for the six months ended June 30, 2010 was $464,000, as compared to future income tax recovery of $1,078,000 for the six months ended June 30, 2009. The future income tax recovery for the nine months ended September 30, 2010 was a result of the Company's renunciation of $1,626,000 of Canadian Exploration Expenditures ("CEE") to investors in January 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. The balance of future income tax liability as at June 30, 2009, which arose because the accounting net book value assigned to the oil and gas properties was in excess of the value of the tax pools, was lower than the balance as at December 31, 2008, resulting in future income tax recovery for the six months ended June 30, 2009.

Foreign exchange gain for the six months ended June 30, 2010 was decreased by $328,000 compared to the same period in 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 for the six months ended June 30, 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 six months ended June 30, 2010.

The decrease in interest and other income was because no management fee income was received from a related party for the six months ended June 30, 2010. During the six months ended June 30, 2009, management fee income was received for financial advisory and project management services provided to the related party.

Net Loss

The Company's net loss for the six months ended June 30, 2010 was $2,822,000 or $0.03 per share, compared to a net loss of $3,230,000, or $0.04 per share for the same period in 2009. The decrease in net loss was mostly attributable to the decreased operating and transportation and depletion expenses, partially offset by lower revenues and higher royalties.

Operating Cash Flow

For the six months ended June 30, 2010, operating cash flow was $485,000 lower than the six months ended June 30, 2009. It was mainly due to lower revenues.

EBITDA and Adjusted EBITDA

For the six months ended June 30, 2010, EBITDA was $431,000 lower than the six months ended June 30, 2009. It was mainly due to lower depletion expenses more than offsetting lower net loss and the add-back of future income tax recovery of $1,078,000 during the six months ended June 30, 2009.

For the six months ended June 30, 2010, Adjusted EBITDA was $849,000 lower than the six months ended June 30, 2009. It was primarily due to negative EBITDA for the six months ended June 30, 2010. During the six months ended June 30, 2009, the add-back of loss on disposition of investment of $274,000 and equity loss from Titan of $142,000 also resulted in a higher Adjusted EBITDA for the period.

SUMMARY OF QUARTERLY RESULTS

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

	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 $	4th Quarter ended December 31, 2008 $	3rd Quarter ended September 30, 2008 $
Revenues	2,768,000	1,305,000	1,346,000	1,056,000	1,682,000	2,702,000	1,853,000	1,678,000
Net loss for the period	(968,000)	(1,915,000)	(7,049,000)	(2,528,000)	(781,000)	(2,449,000)	(15,151,000)	(3,039,000)
Basic and diluted net loss per common share	(0.01)	(0.02)	(0.08)	(0.03)	(0.011)	(0.03)	(0.21)	(0.04)

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. In addition, the substantial loss for the quarter ending December 31, 2008, when compared with the other quarters, was due to the recognition of an impairment loss of $12,990,000 for the investment in Titan in the quarter.

FINANCIAL INSTRUMENTS

The Company's financial instruments consist of cash and cash equivalents, accounts receivable, bridge loan, accounts payable, 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.

At June 30, 2010, the Company had the following risk management contract outstanding:

Product	Period	Production	Fixed Price	Index Price
Gas	July 2010 to October 2010	600 GJ/day	$3.94/GJ	Station 2 Gas Daily Daily Index

For the six months ended June 30, 2010, the Company recognized in income a realized gain of $50,439 on the risk management contracts (2009 - $289,561).

LIQUIDITY AND CAPITAL RESOURCES

Cash Balance and Cash Flow

The Company had cash and cash equivalents of $3,020,000 as of June 30, 2010. In addition to the cash balance, the Company also had accounts receivable of $1,368,000, most of which was related to June 2010 oil and gas sales that had been received subsequent to June 30, 2010.

Our investing activities during the six months ended June 30, 2010 were financed primarily by the $1 million raised from the issuance of flow-through shares and draw down of bridge loan during the period.

In 2009, the Company successfully completed a turnaround on its oil & gas operation to reduce operating costs and improve operating netback. Together with the netback from two successful wells drilled in May 2010, we generated positive operating cash flow of $559,000 commencing the 2nd quarter of 2010. Based on current production forecast and NYMEX oil price of US$80 per barrel and gas price of US$4.50 per Mcf, the Company is expected to generate sufficient operating netback from its oil & gas operations to pay for the general & administration expenses of the Company.

Bank Loan and Bridge Loan Financing

In August 2008, DEAL secured a revolving operating loan facility with a Canadian Bank for up to $7,000,000. In accordance with the terms of the facility, DEAL is required to maintain an adjusted working capital ratio of not less than 1.10:1. The adjusted working capital ratio is defined as the ratio of (i) current assets plus any undrawn availability under the facility, to (ii) current liabilities less any amount drawn under the facility.

As at December 31, 2009, DEAL was in compliance with the working capital ratio requirement. On March 22, 2010, the bank line of credit was completely paid off.

On March 22, 2010, DEAL negotiated a credit facility for a bridge loan of up to $5,000,000. This facility is secured by DEAL's oil and gas assets in Canada. The first $2,000,000 of the facility was available and DEAL utilized $1,500,000 to refinance its existing bank facility and fund the working capital. In June 2010, DEAL received lender's approval for the availability of an additional $1,500,000 of the facility. The availability of the remainder of the facility ($1,500,000) is still subject to the lender's approval. DEAL drew additional $2,000,000 to support the development of its oil and gas properties in the Drake/Woodrush area. The facility carries interest rate at 12% per annum, subject to a 1% fee on any amount drawn and a 2% fee on repayment. DEAL also paid a $50,000 commitment fee.

As of June 30, 2010, a total of $3,500,000 of this facility was utilized. The bridge loan is due on September 22, 2010 and can be extended for a period of maximum 3 months. The extension will be subject to a 1% extension fee per month on the outstanding loan balance at the beginning of each month.

Working Capital Position

As at June 30, 2010, the Company had a working capital deficit of to $4,647,000. The working capital deficit mainly consisted of loans from related parties and bridge loan drawn during the six months ended June 30, 2010. The Company plans to remedy the deficiency through the following:

- Since a new engineering evaluation is completed in July 2010, the Company intends to obtain a credit facility with a conventional bank to refinance the existing bridge loan. Also, the Company is in discussions with the bridge loan lender to extend and increase the existing credit facility.

- In May 2010, the Company successfully brought two new wells into production and generated positive operating cash flow from its oil and gas production in the Woodrush/Drake property. Average production increased to 599 BOE/D in Q2 2010 from 317 BOE/D in Q1 2010. At the current production rate and oil price, we expect to generate an operating netback of approximately $400,000 per month for at least the remainder of 2010, which would be sufficient to fund general overhead expenses.

- If necessary and at the right market conditions, the Company may fund its working capital through additional debt or disposal of non-core asset or a combination of both.

Capital Resources

The Company plans to drill at least two wells in Canada during the remainder of 2010. The Company also plans to drill an exploratory well in an oil prospect at South Rangely in the US.

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

Contractual Obligations

As of June 30, 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)	2010	2011	2012	2013	2014	Thereafter	Total
	$	$	$	$	$	$	$
Operating Lease Obligations	68	73	73	73	49	Nil	336
Bridge Loan	3,500	-	-	-	-	Nil	3,500
Other Obligations	2,458	-	-	-	-	Nil	2,458
Total	6,026	73	73	73	49	Nil	6,294

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.

TRANSACTION WITH RELATED PARTIES

HEC loan to the Company

In 2009, the Company entered into an agreement with HEC in regard to the outstanding debt of $1,800,000 assumed from DEAL by the Company. Pursuant to the agreements, $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. $1,350,000 of the debt was converted into a 12% note due on January 1, 2011 and the Company is required to pay 3% fee on the outstanding balance of the loan as at December 31, 2009. As a result of the sale of 5% working interest in the Drake/Woodrush area to HEC in December 2009, both parties were agreed to reduce the loan balance by the purchase price after taxes and adjustments of $911,722. In addition, the loan balance was further reduced by a payment of $50,351. As at June 30, 2010 and December 31, 2009, $387,927 remained outstanding.

Brownstone loan to the Company

In 2008, Brownstone Ventures Inc. ("Brownstone"), a company which owns more than 10% of outstanding common shares of the Company and one of Brownstone's directors also serves on the board of directors of the Company, provided the Company with a $4,078,800 (US $4,000,000) secured loan, which was used to purchase the additional acreage interests in the Colorado/Utah Projects. During 2008, a repayment of $222,948 (US$220,000) was made and a balance of $4,604,040 (US$3,780,000) was outstanding as at December 31, 2008.

During 2009, the Company entered into agreements with Brownstone in regard to the outstanding debt of $4,604,040 (US$3,780,000). Pursuant to the agreements, 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 fair value of the units was estimated to be US$2,000,000. The remaining US$1,780,000 (C$2,070,140) of the debt was converted into a Canadian dollar denominated 12% note due on January 1, 2011.

LITIGATION

The Company was involved in a termination claim and litigation from a former officer and director. In February 2010, both parties agreed to settle the claim and the Company made a settlement payment of $100,000 to the former director and officer.

SUBSEQUENT EVENT

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.

Subsequent to June 30, 2010, the Company purchased 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	September 2010	7,000 barrels per month	US$70
WTI Crude oil put options	October 2010	7,000 barrels per month	US$70
WTI Crude oil put options	November 2010	7,000 barrels per month	US$70
WTI Crude oil put options	December 2010	7,000 barrels per month	US$70

In addition, the Company sold the following written call options, allowing the purchaser the right, but not the obligation, to buy Western Texas Instrument ("WTI") crude oil:

Crude oil Contract	Contract Month	Volume	Price per barrel
WTI Crude oil call options	October 2010	5,000 barrels per month	US$90
WTI Crude oil call options	November 2010	5,000 barrels per month	US$90
WTI Crude oil call options	December 2010	5,000 barrels per month	US$90

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, as well as accounting for property, plant and equipment, asset impairment testing, and income taxes.

In 2010 Q3 and Q4, the Company continues to work through 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 will also assess the impact the changeover will have on current policies and procedures, information technology and accounting systems, as well as internal controls.

Additionally, in 2010, the Company will address 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 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 2008 and 2009, 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.

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 June 30, 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 June 30, 2010, as amended, 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 June 30, 2010, as amended, 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.

The Company plans to remedy the weaknesses by improving 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.

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 MEASURE

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.