DEJOUR ENTERPRISES LTD.

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ANNUAL INFORMATION FORM
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2007

MARCH 21, 2008

TABLE OF CONTENTS

PRELIMINARY NOTES

In this Annual Information Form ("AIF"), Dejour Enterprises Ltd. is referred to as "Dejour" or the "Company". All information contained herein is as at December 31, 2007 or the date of the AIF, being March 21, 2008, unless otherwise stated.

Financial Statements

This AIF should be read in conjunction with the Company's consolidated financial statements and management's discussion and analysis for the 12 months ended December 31, 2007. The financial statements and management's discussion and analysis are available under the Company's profile on the SEDAR website at www.sedar.com. All financial statements are prepared in accordance with Canadian generally accepted accounting principles.

Currency

All sums of money which are referred to in this AIF are expressed in lawful money of Canada, unless otherwise specified.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This AIF and the documents incorporated by reference herein contain "forward-looking statements" within the meaning of securities legislation and the United States Private Securities Litigation Reform Act of 1995. The forward-looking statements and forward looking information are based upon the Company’s current internal expectations, estimates, projections, assumptions and beliefs. In some cases, words such as "plan", "expect", "project", "intend", "believe", "anticipate", "estimate", "may", "will", "potential", "proposed" and other similar words, or statements that certain events or conditions "may" or "will" occur, are intended to identify forward-looking statements and forward-looking information. These statements are not guarantees of future performance and involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in the forward-looking statements or information. In addition, this AIF may contain forward-looking statements and information attributed to third party industry sources. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur. Such forward-looking statements and information in this AIF speak only as of the date of this AIF.

Forward-looking statements and information in this AIF include, but are not limited to, statements with respect to:

- drilling inventory, drilling plans and timing of drilling, re-completion and tie-in of wells;
- productive capacity of wells, anticipated or expected production rates and anticipated dates of commencement of production;
- drilling, completion and facilities costs;
- results of various projects of the Company;
- ability to lower cost structure in certain projects of the Company;
- growth expectations within the Company;
- timing of development of undeveloped reserves;
- the tax horizon of the Company;
- the performance and characteristics of the Company’s oil and natural gas properties;
- oil and natural gas production levels;
- the quantity of oil and natural gas reserves;
- capital expenditure programs;

- supply and demand for oil and natural gas and commodity prices;
- the impact of Canadian federal and provincial governmental regulation on the Company relative to other oil and gas issuers of similar size;
- weighting of production between different commodities;
- expected levels of royalty rates, operating costs, general administrative costs, costs of services and other costs and expenses;
- expectations regarding the Company's ability to raise capital and to continually add to reserves through acquisitions, exploration and development;
- treatment under governmental regulatory regimes and tax laws; and
- realization of the anticipated benefits of acquisitions and dispositions.

Although the Company believes that the expectations reflected in the forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. The Company cannot guarantee future results, levels of activity, performance or achievements. Consequently, there is no representation by the Company that actual results achieved will be the same in whole or in part as those set out in the forward-looking statements and information. Some of the risks and other factors, some of which are beyond the Company's control, which could cause results to differ materially from those expressed in the forward-looking statements and information contained in this AIF, but are not limited to:

- general economic conditions in Canada, the United States and globally;
- industry conditions, including fluctuations in the price of oil and natural gas;
- governmental regulation of the oil and gas industry, including environmental regulation;
- geological, technical, drilling and processing problems and other difficulties in producing reserves;
- failure to realize anticipated benefits of acquisitions;
- unanticipated operating events which can reduce production or cause production to be shut in or delayed;
- failure to obtain industry partner and other third party consents and approvals, when required;
- stock market volatility and market valuations;
- competition for, among other things, capital, acquisitions of reserves, undeveloped land and /skilled personnel;
- competition for and/or inability to retain drilling rigs and other services;
- the availability of capital on acceptable terms;
- the need to obtain required approvals from regulatory authorities; and
- the other factors disclosed under *"Risk Factors"* in this AIF.

Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described can be profitably produced in the future. Readers are cautioned that the foregoing list of factors is not exhaustive. **The forward-looking statements contained in this AIF are expressly qualified by this cautionary statement. The Company is not under any duty to update any of the forward-looking statements after the date of this AIF to conform such statements to actual results or to changes in the Company's expectations except as otherwise required by applicable legislation.**

ABBREVIATIONS

In this AIF, the following abbreviations have the meanings indicated:

Oil and Natural Gas Liquids

bbl	barrel
bbls	barrels
bbls/d	barrels per day
Mbbls	thousand barrels
MMbbls	million barrels
NGL	natural gas liquids

Natural Gas

Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMcf	million cubic feet
MMcf/d	million cubic feet per day
GJ	gigajoule

Other

AECO	Intra-Alberta Nova Inventory Transfer Price (NIT net price of natural gas).
API	An indication of the specific gravity of crude oil measured on the American Petroleum Institute gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil.
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.
bf/d	Barrels of fluid per day.
bw/d	Barrels of water per day.
IT	Imperial tone.
m	Metre.
m^3	Cubic metre.
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.

PRESENTATION OF OIL AND GAS RESERVES AND PRODUCTION INFORMATION

All oil and natural gas reserve information contained in this AIF has been prepared and presented in accordance with National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101"**). The actual oil and natural gas reserves and future production will be greater than or less than the estimates provided in this AIF. The estimated future net revenue from the production of the disclosed oil and natural gas reserves does not represent the fair market value of these reserves. **The Company has adopted the standard of 6 Mcf:1 boe when converting natural gas to barrels of oil equivalent. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf:1 boe is based on an energy**

equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

In respect of reserves data contained in this AIF, the following terms have the meanings indicated:

"**developed non-producing reserves**" are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

"**developed producing reserves**" are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

"**gross**" means the working interest (operated and non-operated) share before deduction of royalties and without including any royalty interest.

"**net**" means the working interest (operated and non-operated) share after deduction of royalty obligations, plus the Company's royalty interests in reserves.

"**probable reserves**" are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. At least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves is the targeted level of certainty.

"**proved developed reserves**" are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

"**proved plus probable reserves**" means the aggregate of proved reserves and probable reserves, before deduction of royalties.

"**proved reserves**" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. At least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves is the targeted level of certainty.

"**reserves**" are the estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates.

"**royalties**" refers to royalties paid to others. The royalties deducted from the reserves are based on the percentage royalty calculated by applying the applicable royalty rate or formula. In the case of Crown sliding scale royalties which are dependent on selling prices, the price forecasts for the individual properties in question have been employed.

"**undeveloped reserves**" are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g. when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

CONVERSION FACTORS

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	cubic metres	0.028
cubic metres	cubic feet	35.494
Bbls	cubic metres	0.159
cubic metres	bbls	6.289
Feet	metres	0.305
Metres	feet	3.281
Miles	kilometers	1.609
kilometers	miles	0.621
Acres	hectares	0.405
Hectares	acres	2.471

CORPORATE STRUCTURE

Name, Address and Incorporation

The Company was incorporated under the Company Act (Ontario) on March 29, 1968 under the name "Dejour Mines Limited". By articles of amendment dated October 30, 2001, the issued shares were consolidated on a one (1) new for every fifteen (15) old shares and the name of the company was changed to Dejour Enterprises Ltd. On June 6, 2003, the shareholders approved a resolution to complete a one for three share consolidation which became effective on October 1, 2003. In 2005, the Company was continued into British Columbia under the Business Corporations Act (British Columbia).

The head office address of Dejour is located at Suite 1100 - 808 West Hastings Street, Vancouver, British Columbia, V6C 2X4 and its registered and records office is located at 10th Floor, 595 Howe Street, Vancouver, British Columbia, V6C 2T5, telephone (604) 638-5058. The common shares of Dejour are listed for trading on the TSX Venture Exchange ("TSXV") under the symbol DEJ.V, the American Stock Exchange ("AMEX") under the symbol "DEJ" and on the Frankfurt Exchange (‘FWB”) under the symbol “D5R”.

Intercorporate Relationships

The Company has two subsidiaries: 100% owned Dejour Energy (USA) Corp holds the Company’s oil & gas properties in the United States and 100% owned Dejour Energy (Alberta) Ltd. holds its oil & gas properties in Canada.

GENERAL DEVELOPMENT OF THE BUSINESS

The Company is in the business of locating, acquiring and exploring natural resource properties. Its strategy is to grow production from an expanding resource base in order to become an intermediate international gold company.

Three Year History:

Uranium:

Beginning in early 2005, Dejour began the business of exploration for uranium with the staking of its first mining claims located in the Athabasca Basin in northern Saskatchewan (the “Basin”). In less than 2 years the Company staked or acquired mineral rights to 68 claims and 4 permits consisting of 966,969 acres (391,320 hectares) with the Company owning 100% of the interest. The Company had spent approximately $7.0 million in acquisition and exploration on its uranium properties.

On October 26, 2006, Dejour announced that it would sell all of its uranium property interests to Titan Uranium Incorporated ("Titan"), a company that trades on the TSXV under the symbol "TUE". Pursuant to this acquisition Titan paid Dejour 17,500,000 fully paid and assessable common shares in Titan. Titan also paid Dejour 3,000,000 transferable common share purchase warrants, entitling the holder to acquire up to 3,000,000 common shares in the capital of Titan at an exercise price of $2.00 per common share for a period of 24 months, subject to a forced exercise position whereby Titan can call the automatic exercise of the warrants in the event that Titan’s common shares trade on the TSX Venture Exchange at a price of $4.00 or more for twenty consecutive trading days. Dejour retained a 1% Net Smelter Return ("NSR") on all contributed properties. Dejour also retained a 10% working interest in each claim carried by Titan to a completed bankable feasibility study after which Dejour may elect to participate as to its 10% interest or convert to an additional 1% NSR. Titan agreed to provide Dejour with a first right of refusal on all future financing, as long as Dejour’s ownership in the stock of Titan is greater than 10% of the outstanding shares. Dejour is to provide two full-time and one part-time geologist on terms to be agreed and Titan is to appoint two Dejour representatives to the Titan Board of Directors.

The above sale was closed in escrow on December 15, 2006. Following approval by the shareholders of Titan and Dejour at their respective meetings held on January 22, 2007 and on February 2, 2007, the sale was completed.

US Properties:

Piceance & Unita Basins

Since 2006, Dejour acquired a working interest in approximately 200,000 gross acres in the Piceance Uinta Basins located in Colorado and Utah respectively. The original petroleum leases were purchased for approximately $25 million USD from Retamco Operating, Inc., a U.S. privately owned oil and gas exploration company, for a 25% net working interest in 23 Natural Gas Resource Prospects. The Company also purchased from Retamco a 12.5% net working interest in a large Overthrust Prospect of 71,294 acres.

Dejour and its partners have 4 separate drilling locations at the North Barcus Creek (NBC) prospect. The first two wells, NBC #1-12 and #2-12 were successfully drilled and logged at the end September 2007. A preliminary petrophysical analysis of the #1-12 well logs, evaluated by Gustavson Associates, reported reservoir properties consisting of an estimated 263 feet of potential net pay with average porosity of 10% and NBC #2-12 well logs an estimated 254 feet of potential net pay. Casing has been set to total depth in both. Completion and testing at both NBC #1-12 and #2-12 was stopped due to poor weather conditions in early January 2008 and is anticipated to recommence, weather permitting, early April 2008. The operator has advised Dejour that comprehensive flow rate data for each of the wells should be established by Q2 of 2008. It is expected that these lands could be fully developed on maximum 40 acre spacing units. Accessible pipeline facilities are within one mile of the lease boundaries.

Tinsley

By agreement dated September 1, 2005 the Company acquired the rights to participate in an oil and gas exploration joint venture known as the Tinsley Deep Prospect located in Yazoo County, Mississippi (the "Tinsley Prospect"). The Tinsley Prospect originally comprised of 5,100 gross acres and 4,613 net acres. During December 2005 the operator commenced drilling operations on a test well known as the Merit Partners #1, eventually drilled to a total depth of 11,237 feet.

In March 2006, the Company was advised by the operator of the Tinsley Prospect that the well was not economic.

In the 1st quarter of 2007 the Company reached an agreement with the Operator such that the Company transferred its interest in the Merit Partners #1 well bore along with certain shallow rights in roughly 616 net acres of oil & gas leases and in return the Company received 100% ownership of 1,736 net acres of oil & gas leases containing the rights below the base of the Hosston formation. The Company will not be required to pay its share of plugging and abandonment costs for the Merit Partners #1 well bore.

In 2007, the Company concluded an agreement with a private Mississippi based company with the Company contributing its land and technical information from the Tinsley Prospect to a joint venture. The Mississippi based corporation has acquired additional leasehold interests, identified additional partners and an operator and together with the Company plans the drilling of additional wells over the next 12 months.

Canadian Properties:

Peace River Arch

Since 2006, Dejour Energy (Alberta) Ltd., a wholly owned subsidiary of the Company, has acquired 45,000 gross acres, which comprises of 14 prospect areas in the Peace River Arch. This region is located in northeast British Columbia and northwest Alberta.

Dejour has drilled 9 of its 14 prospect areas. To date, six prospects have been successfully produced which have resulted in 11 wells of which 9 are operated by the Company. The average working interest is 80 %. Total estimated exploration costs to date are anticipated to be CDN $18M. Going forward, the Company plans to drill the other 5 prospect areas and continue strategic land acquisitions.

Financings

The Company completed the following private placement financings in 2005:

1. 8,076,923 units at $0.65 per unit, each unit consisting of one common share and one half of one transferable common share purchase warrant. Each whole share purchase warrant was exercisable into one additional common share of the Company at a price of $0.80 per common share until March 17, 2007.

2. 1,650,000 shares at $0.50 per share to raise gross proceeds raised of $825,000.

3. 4,500,000 units at a price of US$0.55 per unit for gross proceeds of Cdn$2,914,808. Each unit consisted of one common share and one-half of one share purchase warrant with each whole share purchase warrant entitling the holder to purchase an additional common share of the Company at a price of $0.80 per share to March 17, 2007.

4. 4,317,500 units at $0.95 per unit and 2,300,000 flow through common shares at $1.05 per share for total gross proceeds of $6,516,625. Each unit consisted of one common share and one-half of one share purchase warrant with each whole share purchase warrant entitling the holder to purchase an

additional common share of the Company at a price of $1.10 per share to December 14, 2007.

The Company completed the following private placement financings in 2006:

1. 5,300,000 flow-through shares at a price of $1.50 per flow-through share to raise gross proceeds raised of $7,950,000.

2. 2,771,333 units at a price of $1.50 per unit raising gross proceeds of $4,157,000. Each unit consisted of one common share and one-half of one common share purchase warrant. Each whole common share purchase warrant entitled the holder to purchase one additional common share at a price of $1.65 per common share until December 31, 2007.

3. 5,500,000 common shares were issued to Retamco Operating Co. in partial payment for Dejour's interest in the Retamco Oil & Gas Project located in western Colorado and eastern Utah.

The Company completed the following private placement financings in 2007:

1. 3,773,980 units at $2.65 per unit for gross proceeds of $10,001,047. Each unit consisted of one common share and one-half of one share purchase warrant with each whole share purchase warrant entitling the holder to purchase an additional common share of the Company at a price of $3.35 per share to December 31, 2008.

2. 1,000,000 flow-through shares at a price of $1.82 per flow-through share to raise gross proceeds raised of $1,820,000.

DESCRIPTION OF THE BUSINESS

,) such that the current total of leases is 295. These additional 28 leases are contained within an Area of Mutual Interest as defined in the 2006 purchase agreement.

The projects consist of two types. The Company holds a 25% working interest in the "Natural Gas Resource" projects which are a well defined stratigraphic gas resource, covering 207,934 net acres containing low geologic risk natural gas assets plus the opportunity for deeper Jurassic reserves. The Company holds a 12.5% interest in the second project, a massive deep "Subthrust Oil" project covering 68,000 net acres in the northern Piceance/Uinta Basins with a high reward potential and commensurate risk. According to the Operator, the Subthrust project has prospective resource estimates of 2 billion barrels of oil, and is directly analogous to the Rangeley field located immediately adjacent; having produced over 1 billion barrels to date.

Leasehold acreage net royalty interest ("NRI") is 80% except for 1 lease that is 78%. Dejour will pay an unpromoted proportionate share of all exploration expenses including seismic, drilling, completion or abandonment and equipping.

On July 2, 2007 the Company received 2 AFE's (Authorities For Expenditure) from the Operator proposing the drilling of 2 wells on its N. Barcus Creek Prospect located in Rio Blanco County, Colorado. The Company elected to participate in the drilling of the 2 proposed wells, known as the #1-12 and #2-12 wells, located in Section 12, T1N, R99W.

The #1-12 well is a direct offset to a well drilled in 1979 to 15,700' known as the Federal #22-12 well. Prior to commencement of drill operations the Company engaged Gustavson Associates, Boulder Colorado (Geologists – Engineers - Appraisers) to conduct a petrophysical analysis of the Federal #22-12 well in comparison with the proposed #1-12 and #2-12 wells. In its report, Gustavson discloses that it is their interpretation from log analysis and tests run on the #22-12 well, that there exist reservoir properties inclusive of over 260’ of possible pay, that are similar to other wells in the Rio Blanco County area which produce gas from the Williams Fork/Mesaverde formations.

On July 22, 2007 a shallow capable drill rig commenced drill operations and by August 8, 2007 had drilled to a depth of 3,225’ and subsequently set surface casing. The shallow drill rig was released; a deeper capable rig moved in and on August 16, 2007 continued drill operations. On August 27, 2007 the deeper rig reached the target depth of 11,150’ and on September 2, 2007 rig was released. Operations to complete the #1-12 well commenced on September 13, 2007 and have continued thru the present. The well awaits connection to a pipeline.

Drill operations on the #2-12 well commenced on August 7, 2007 when the shallow rig utilized on the #1-12 well was relocated to the #2-12 location. The #2-12 well is within 1,800’ of the #1-12 well. The #2-12 well was drilled to a depth of 3,260’ and surface casing was set. The shallow drill rig was released and the deeper rig, the same one utilized for the deepening of the #1-12 well, was mobilized and on September 8, 2007 continued drill operations. On September 21, 2007 the deeper drill rig reached the target depth of 11,300’ and on September 24, 2007 the deeper drill rig was released. Operations to complete the #2-12 well commenced on September 25, 2007 and shortly thereafter were suspended pending results of the #1-12 well. After some delay the completion program recommenced and currently the well is shut in pending installation of a pipeline. Negotiations are underway to install a pipeline to allow production from the N. Barcus Creek wells.

The Operator also has advised the company that it has received approval to allow it to drill 2 additional wells on the N. Barcus Creek acreage.

The current working interest partners are:

	‘Natural Gas Resource’	‘Subthrust Oil’
Dejour Energy (USA) Corp.	25%	12.5%
Brownstone Ventures (US) Inc.	10%	10%
Retamco Operating, Inc.	65%	77.5%

Tinsley Prospect

By agreement dated September 1, 2005 the Company acquired the rights to participate in an oil and gas exploration joint venture known as the Tinsley Deep Prospect located in Yazoo County, Mississippi (the "Tinsley Prospect"). The Tinsley Prospect originally comprised of 5,100 gross acres and 4,613 net acres. During December 2005 the operator commenced drilling operations on a test well known as the Merit Partners #1, eventually drilled to a total depth of 11,237 feet.

The Company paid acquisition costs representing the Company's 43% prospect interest which included payment for leasehold interests, brokerage, seismic processing and prospect development. In the initial well the Company paid 46.6% of the drilling and/or abandonment costs, and 34.9% of completion costs to earn a 34.9% WI BPO (working interest before payout) [28.2% NRI BPO (net revenue interest before payout)] and 29.4% WI APO (working interest after payout) [25.6% NRI APO (net revenue interest after payout)]. The agreement also contains an Area of Mutual Interest consisting of approximately 45 sq. miles defined by the area covered by certain seismic data.

In March 2006, the Company was advised by the operator of the Tinsley Prospect that the well was not economic. As a result, the Company recorded an impairment provision of $2,375,926 in 2006.

In the 1st quarter of 2007 the Company reached an agreement with the Operator such that the Company transferred its interest in the Merit Partners #1 wellbore along with certain shallow rights in roughly 616 net acres of oil & gas leases and in return the Company received 100% ownership of 1,736 net acres of oil & gas leases containing the rights below the base of the Hosston formation. The Company will not be required to pay its share of plugging and abandonment costs for the Merit Partners #1 wellbore.

In 2007, the Company concluded an agreement with a private Mississippi based company with the Company contributing its land and technical information from the Tinsley Prospect to a joint venture. The Mississippi based corporation has acquired additional leasehold interests, identified additional partners and an operator and together with the Company plans the drilling of additional wells over the next 12 months.

Lavaca Prospect

By agreement dated October 1, 2005 the Company acquired the rights to participate in oil and gas exploration joint venture known as the Lavaca Prospect located in Mitchell County, Texas (the "Lavaca Prospect"). The Lavaca Prospect was originally comprised of 6,181 gross acres and 3,998 net acres. During November 2005 the operator commenced drilling operations on a test well drilled to 8,200 feet.

The Company paid acquisition costs representing the Company's 10% interest which include payment for leasehold interests, brokerage and prospect development. In the initial well the Company paid 13.3% of the drilling costs and 10% of completion costs estimated at to earn a 10% WI (working interest) [7.5% NRI (net revenue interest)]. The agreement also contains an Area of Mutual Interest consisting of all land within one mile from the outside borders of the leasehold lands.

In September 2006, the Company was advised by the operator of the Lavaca Prospect that the Purvis #1 well is not economic and commenced operations to plug and abandon the well. As a result, the Company recorded an impairment provision of $220,148 in 2006.

Canadian Activities

Commencing April 1, 2006 the Company has entered a joint venture arrangement with Charles W.E. Dove, who has been an advisory board member of the Company since November 2004, and a principal with Dove & Kay Exploration Ltd. of Calgary.

Mr. Dove, a geophysicist, with over 27 years oil & gas experience, left his geophysical consulting business to join with the Company to identify, generate and pursue certain oil & gas opportunities in the Western Sedimentary Basin. The Joint Venture is incorporated as Dejour Energy (Alberta) Ltd. ("DEAL") and was originally owned and funded 90% by the Company, with Mr. Dove's company, Wild Horse Energy Ltd. owning and funding the remaining 10%.

Effective June 1, 2007, the Company purchased Wild Horse Energy Ltd. from Mr. Dove. This purchase resulted in DEAL becoming a wholly owned subsidiary of the Company. The purchase price was based on land and reserve values established by McDaniel and Associates Consultants Ltd., an independent evaluation firm in Calgary, Alberta. Mr. Dove continues as President and COO of DEAL.

Numerous oil and gas prospects are being pursued and developed. DEAL has elected to manage risk by taking varying working interest positions based upon reserve potential and perceived exploration risk. These interests range from 10% to 100%. Most joint venture business terms are structured in such a way that a drilling or re-entry commitment is tied to additional drilling options or other lands on the various prospects. Land purchase priority is given to areas with multi-zone potential and proximal gathering systems.

In October 2006, DEAL successfully concluded a Participation Agreement allowing it to participate in the drilling of a high potential natural gas well in an area known as the Noel Area, in N.E. British Columbia, Canada. DEAL paid 15% of the costs to earn a 9.375% working interest in 2,220 acres with an option to drill additional wells earning 2,220 acres to a maximum of 10,725 acres. Drilling commenced in the 1st quarter of 2007 and the well was dry. The Company had earned the working interest of 2,220 acres, but the Company decided not to exercise options to earn more lands. As a result, the Company recorded an impairment provision of $670,794 for the year ended December 31, 2007.

DEAL has been acquiring lands at public sales and by private purchase. Lands acquisition through purchase or earning has resulted in DEAL owning an average 46% interest in approximately 33,570 acres of lands with further options or a right of first refusal on approximately 5,760 acres in the Peace River Arch area of Alberta.

During the first and second quarters of 2007, DEAL concluded business agreements on four additional prospects resulting with the drilling of four wells and re-entry of a fifth. During the third quarter DEAL purchased 1,419 ha (3,548 acres) of lands and crown sales and privately at an average cost of $420.83/ha ($168.33/acre). Total land bonus paid was $597,163.28. These lands are at 100% working interest. Fourth quarter 2007 activities included the purchase of 1,708 ha (4,270 acres) of land, 1452 (3,630 acres) of which were the Company postings, at government sales for an average of $243.15/ha ($97.26/acre). Total bonus cost for these purchases was $415,302 at 100% working interest. Seismic programs were recorded in three areas, one of these carried over into 2008. These are designed to evaluate lands for drilling in 2008 and 2009.

Results and activity on these prospects are summarized below:

Drake

843 ha (2,108 acres) of the lands purchased in 2007 are in the Drake area of northeast British Columbia. The two gas wells resulting from the Q2 2007 drilling at Drake will be tied in as soon as the permitting is complete and ground conditions permit. Initial rates from these two wells are anticipated to be approximately 1.5 mmcf/day net to the Company. For the 2007/2008 winter drilling season a total of four new wells, three of

which will be drilled to evaluate the deeper Halfway formation as well as the proven Notikewin sands, are planned. Two are on lands earned by last winters' drilling and two on 100% working interest lands purchased at a crown sale. Working interest in lands earned last winter has been increased from 60% to 92% on 700 of the 1,400 acres earned. Interest in the remaining 700 acres remains at 100% before payout and 60% after payout. Final locations for the 2007/8 winter drilling were chosen based on interpretation of 3D seismic data purchased over all the Company's working interest land in the area. Subsequent to the year ended December 31, 2007, the four wells were drilled and completed for production. Pipelines and equipment are currently being placed to produce these wells. These new wells tested at flow rates of 500 to over 1600 mcf/day. Infrastructure in the Drake area will have design capabilities to handle up to 10 mmcf/day.

Wembley

At Wembley, Alberta, an existing well bore was re-entered and a re-completion attempted in the Notikewin formation during the 2006/7 winter. The Company earned a 50% working interest in a 100% before payout, 60% after payout farm-in in on two sections with the re-entry. This resulted in non-economic gas; however, it allowed the Company to continue four section of land past lease expiry to evaluate two other prospective zones. An exploration well commenced drilling in late December to test these zones. A partner company was invited into this prospect during drilling reducing the Company's interest from 100 to 70%. The well was completed in early 2008 and tested under 100 mcf/day and was deemed non-economic.

Chinchaga

At Chinchaga, Alberta, the Company participated for a 10% working interest in a Slave Point test well in Q1 2007. This was on a farm-in whereby the Company reimbursed the land holder for 10% of land costs subject to a royalty of 12.5% on 7,680 acres and 7.5% on 5,120 acres of the 12,800 acres included in the farm-out. A well was drilled on a seismically defined anomaly similar to the Ladyfern 30 miles to the west. Although this well was not economic, the results are being evaluated which may lead to further drilling in the area. The Company elected to increase its interest to 45% in 2,560 acres prior to completion of drilling of the test well. In addition the company has a ROFR on 5,760 acres.

Saddle Hills

In the Saddle Hills area, in Q1 2007 DEAL participated in drilling a well on a five section block of land at 30% working interest to earn 30% subject to 10% non-convertible royalty. The operator expects to tie in the gas well drilled last winter and drill one location in Q2 2008. The Company is operating a seismic program on behalf of the joint venture to aid in future development plans. Last winters gas well tested over 1.5 mmcf/day total from two zones. Agreements are being finalized to add 7 sections at 30% working interest.

Manning

The Company participated at 40% working interest in a farm-in on seven sections of land. A test well commenced drilling in December 2007 and will be completed in early 2008. This well will earn all seven sections subject to non-convertible royalty.

LaGlace

At LaGlace, the company purchased a quarter section of land privately to test a shallow oil play. The well was drilled and cased in December 2007 and will be completed and evaluated in 2008.

Cecil

A seismic program was recorded at Cecil. Based on this program, a well was drilled Q1 2008 and the Company expects to tie-in the well for production in Q2 2008. The Company’s interest in this prospect is 95%.

Boundary Lake

Land was posted and purchased in B.C. and Alberta in this area. An exploration well is drilled and cased in Q1 2008 and is in the process of being evaluated.

Carson Creek

At Carson Creek, land was purchased privately and a test well commenced drilling in late 2007. This well was completed and will be placed on production as soon as possible.

Kaybob

Land was posted and purchased in the Kaybob area. A seismic program began operation in Q4 2007 and was completed in January 2008. This will guide future development plans for this oil prospect.

Future Plans

The Company is adding oil prospects to its inventory of prospects in Alberta will continue an aggressive development plan for the prospects at Drake B.C. To facilitate the growing operation, DEAL has been increasing its working interests in prospects and has obtained the required permits to drill and operate oil and gas properties in Alberta and British Columbia The Company has added additional contract personnel to assist with lands and engineering requirements and is pursuing additional lands to expand on current success.

Risk Factors

Investment in securities of Dejour involves a significant degree of risk and should be considered speculative due to the nature of Dejour’s business and the present stage of its development.

The following is a brief description of those distinctive or special characteristics of Dejour's operations and industry, which may have a material impact on, or constitute risk factors in respect of Dejour's financial performance, business and operations.

Risks Pertaining to the Company:

An investment in the Company is speculative due to the nature of the Company's involvement in the exploration for, and the acquisition, development and production of, oil and natural gas reserves. An investor should consider carefully the risk factors set out below and consider all other information contained herein and in the Company's other public filings before making an investment decision.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Company depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, the Company's existing reserves and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Company's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Company will be able to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, management of the Company may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Company.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, the Company may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Company. In accordance with industry practice, the Company is not fully insured against all of these risks, nor are all such risks insurable. Although the Company maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Company could incur significant costs that could have a material adverse effect upon its financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks could have a material adverse effect on the Company.

Operational Dependence

Other companies operate some of the assets in which the Company has an interest. As a result, the Company has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Company's financial performance. The Company's return on assets operated by others will therefore depend upon a number of factors that may be outside of the Company's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Project Risks

The Company will manage a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic.

The Company's ability to execute projects and market oil and natural gas will depend upon numerous factors beyond the Company's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Company could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

Absence of Infrastructure to Transport the Company's Gas Production

Due to the location of certain of the Company's assets both Canada and US there is minimal infrastructure currently available to transport natural gas from the Company's existing and future wells to market.

Production Transportation Plans

As a result of the absence of infrastructure to transport the Company's gas production, the Company is presently constructing pipeline in the Drake area of northeast area of British Columbia and related gathering system, and negotiations are presently underway to install a pipeline to allow production from the North Barcus Creek wells located in Rio Blanco County, Colorado which would enable the Company to transport its natural gas to market.

Seasonal Factors

Oil and natural gas development activities, including seismic and drilling programs in Northern Alberta and British Columbia are restricted to those months of the year when the ground is frozen. Seasonal weather variations, including freeze-up and break-up, will affect access.

Competition

The petroleum industry is competitive in all its phases. The Company competes with numerous other organizations in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Company's competitors will include oil and natural gas companies that have substantially greater financial resources, staff and facilities than the Company. The Company's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery and storage.

Regulatory

Oil and natural gas operations (exploration, production, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. See "Industry Conditions". Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for natural gas and crude oil and increase the Company's costs, any of which may have a material adverse effect on the Company's business, financial condition and results of operations. In order to conduct oil and gas operations, the Company requires licenses from various governmental authorities. There can be no assurance that the Company will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

New Alberta Royalty Regime

On October 25, 2007, the Alberta government released a report entitled "The New Royalty Framework" (the "**NRF**") containing the government's proposals for Alberta's new royalty regime which is scheduled to be effective on January 1, 2009. Given that the NRF has only recently been announced, it is not possible at this time to determine the full impact of the NRF on the Company's financial condition and operations.

The Company cannot provide any assurance that the NRF will be implemented in the form proposed. If changes are made to the NRF before it is implemented by the Alberta government, such changes could result in the implementation of a new royalty regime that impacts the Company in a materially different manner, and that is more adverse to the Company, than the NRF as currently proposed.

Kyoto Protocol

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". The Company's exploration and production facilities and other operations and activities emit greenhouse gases which will likely subject the Company to possible future legislation regulating emissions of greenhouse gases, such as the government of Canada's proposed *Clean Air* Act of 2006 and Alberta's recently enacted *Climate Change and Emissions Management Act.* The direct or indirect costs of these regulations may adversely affect the expected business of the Company. See "Industry Conditions – Environmental Regulation".

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Company to incur costs to remedy such discharge. Although the Company believes that it is in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect the Company's financial condition, results of operations or prospects. See "Industry Conditions – Environmental Regulation".

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by the Company is and will continue to be affected by numerous factors beyond its control. The Company's ability to market its oil and natural gas depends upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. The Company is also affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

Both oil and natural gas prices are unstable and are subject to fluctuation. Any material decline in prices could result in a reduction of the Company's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or gas and a reduction in the volumes of the Company's reserves. The Company might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Company's net production revenue and a reduction in its oil and gas acquisition, development and exploration activities.

Variations in Foreign Exchange Rates and Interest Rates

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore effected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Such material increases in the value of the Canadian dollar may negatively impact the Company's operating entities production revenues. Further material increases in the value of the Canadian dollar would exacerbate this potential negative impact. This increase in the exchange rate for the Canadian dollar and future Canadian/United States exchange rates could accordingly impact the future value of the Company's reserves as determined by independent evaluators.

To the extent that the Company engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Company may contract.

Substantial Capital Requirements

The Company anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If the Company's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Company. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on the Company's financial condition, results of operations and prospects.

Additional Funding Requirements

The Company's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Company may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Company to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Company's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, the Company's ability to expend the necessary capital to replace its reserves or to maintain its production will be impaired. If the Company's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on favourable terms.

Issuance of Debt

From time to time the Company may enter into transactions to acquire assets or the shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase the Company's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Company may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Company's notice of articles nor its articles limit the amount of indebtedness that the Company may incur. The level of the Company's indebtedness from time to time, could impair the Company's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Hedging

From time to time the Company may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Company will not benefit from such increases. Similarly, from time to time the Company may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, the Company will not benefit from the fluctuating exchange rate.

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Company and may delay exploration and development activities. To the extent the Company is not the operator of its oil and gas properties, the Company will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Company's claim which could result in a reduction of the revenue received by the Company.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGL reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this document are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. All such estimates are to some degree speculative, and classifications of reserves are only attempts to define the degree of speculation involved. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

In accordance with applicable securities laws, GLJ Petroleum Consultants Ltd. and Gustavson Associates LLC have used both constant and forecast prices and costs in estimating the reserves and future net cash flows contained in their respective reports. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from the Company's oil and gas reserves will vary from the estimates contained in the GLJ Petroleum Consultants Ltd. and Gustavson Associates LLC reports, and such variations could be material. Both reports are based in part on the assumed success of activities the Company intends to undertake in future years. The reserves and estimated cash flows set out in both reports will be reduced to the extent that such activities do not achieve the level of success assumed in the reports.

Insurance

The Company's involvement in the exploration for and development of oil and natural gas properties may result in the Company becoming subject to liability for pollution, blow outs, property damage, personal injury or other hazards. Although the Company will maintain insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, such risks are not, in all circumstances, insurable or, in certain circumstances, the Company may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Company. The occurrence of a significant event that the Company is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on the Company.

Geo-Political Risks

The marketability and price of oil and natural gas that may be acquired or discovered by the Company is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle-East, and other areas of the world, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of the Company's net production revenue.

In addition, the Company's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. As the oil and gas industry in Canada is a key supplier of energy to the United States, certain terrorist groups may target Canadian oil and gas properties, wells and facilities in an effort to choke the United States economy. If any of the Company's properties, wells or facilities are the subject of terrorist attack it could have a material adverse effect on the Company. The Company does not have insurance to protect against the risk from terrorism.

Dividends

Any decision to pay dividends on the shares of the Company will be made by the Board of Directors on the basis of the Company's earnings, financial requirements and other conditions existing at such future time. See "Dividend Record and Policy".

Conflicts of Interest

Certain directors of the Company are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the Business Corporations Act (British Columbia). See "Directors and Officers – Conflicts of Interest".

Dilution

The Company may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Company which may be dilutive.

Management of Growth

The Company may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Company to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of the Company to deal with this growth could have a material adverse impact on its business, operations and prospects.

Expiration of Licenses and Leases

The Company's properties are held in the form of licences and leases and working interests in licences and leases. If the Company or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Company's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the Company's results of operations and business.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of Western Canada. The Company is not aware that any claims have been made in respect of its property and assets; however, if a claim arose and was successful this could have an adverse effect on the Company and its operations.

Seasonality

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Company.

Third Party Credit Risk

The Company may be 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 could have a material adverse effect on the Company and its cash flow from operations. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Company's ongoing capital program, potentially delaying the program and the results of such program until the Company finds a suitable alternative partner.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The report of management and the directors on oil and gas disclosure in Form 51-101F2 and the report on reserves data in Form 51-101F3 are attached as Schedules "A" and "B", respectively, to this Annual Information Form, which forms are incorporated herein by reference.

Disclosure of Reserves Data

All of the Company's reserves herein reported were evaluated by independent evaluators in accordance with NI 51-101for the year ended December 31, 2007. In 2008, GLJ Petroleum Consultants, (‘GLJ”) independent petroleum engineering consultants based in Calgary, Alberta were retained by the Company's to independently evaluate the Canadian properties of the Company. Their report is dated March 28, 2008. Gustavson Associates (‘Gustavson”) of Denver Colorado were retained in 2007 by the Company to independently evaluate the US properties of the Company and is dated March 14, 2008.

The reserves data set forth below (the "Reserves Data") was prepared by GLJ and Gustavson with an effective date of December 31, 2007. The Reserves Data summarizes the oil, liquids and natural gas reserves of the Company and the net present values of future net revenue for these reserves using constant prices and costs and forecast prices and costs. The Company reports in Canadian currency and therefore the reports have been converted to Canadian dollars at the prevailing conversion rate at December 31, 2008.

The Reserves Data conforms with the requirements of NI 51-101.

Disclosure provided herein in respect of BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
All evaluations and reviews of future net cash flow are stated prior to any provision for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned. It should not be assumed that the estimated future net cash flow shown below is representative of the fair market value of the Company's properties. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, NGLs and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, NGLs and natural gas reserves may be greater than or less than the estimates provided herein.

a) Summary of Oil and Gas Reserves

As of December 31, 2007	LIGHT & MED. OIL Mbbl		NATURAL GAS mmcf		NAT. GAS LIQUIDS Mbbl		LIGHT & MED. OIL Mbbl COMPANY TOTAL	NATURAL GAS mmcf COMPANY TOTAL	NAT. GAS LIQUIDS Mbbl COMPANY TOTAL
	CAN.	USA	CAN.	USA	CAN.	USA			
RESERVES CATEGORY									
PROVED									
Developed producing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Developed Non-Producing	0.0	8.1	241.0	168.6	5.0	0.0	8.1	409.6	5.0
Undeveloped	0.0	0.0	1584.0	0.0	0.0	0.0	0.0	1584.0	0.0
TOTAL PROVED	**0.0**	**8.1**	**1825.0**	**168.6**	**5.0**	**0.0**	**8.1**	**1993.6**	**5.0**
PROBABLE	222.0	429.9	1212.0	4584.3	20.0	0.0	651.9	5796.3	20.0
TOTAL PROVED PLUS PROBABLE	**222.0**	**438.0**	**3037.0**	**4752.9**	**25.0**	**0.0**	**660.0**	**7789.9**	**25.0**
POSSIBLE USA ONLY		434.0		4807		0			
PROVED PLUS PROBABLE PLUS POSSIBLE	**222.0**	**872.0**	**3037.0**	**9560.0**	**25.0**	**0.0**	**1094.0**	**12597.0**	**25.0**

PROVED	
TOTAL COMPANY Mboe	**345.4**
TOTAL COMPANY Mmcfe	**2072.2**
PROVED PLUS PROBABLE	
TOTAL COMPANY Mboe	**1983.3**
TOTAL COMPANY Mmcfe	**11899.9**
TOTAL COMPANY PROVED PLUS PROBABLE PLUS POSSIBLE	
TOTAL COMPANY Mboe	**3218.5**
TOTAL COMPANY Mmcfe	**19311.0**

b) Net Present Value of Future Net Revenue - Before Income Taxes

Forecast Price as of December 31, 2007

Reserve Location

		CDN M$	CDN M$	CDN $M	CDN M$	CDN M$
	Discount rate %	0	5	10	15	20
Canada	**GLJ Petroleum Consultants Ltd.**					
	Prepared March 27, 2008					
	Developed Producing	$ 787	$ 558	$ 427	$ 344	$ 288
	Developed Non-Producing	$ 1,744	$ 1,119	$ 637	$ 258	$ (42)
	Undeveloped					
	TOTAL PROVED CANADA	**$ 2,531**	**$ 1,677**	**$ 1,064**	**$ 602**	**$ 246**
	PROBABLE	$ 3,835	$ 2,874	$ 2,209	$ 1,730	$ 1,373
	TOTAL PROVED PLUS PROBABLE	**$ 6,366**	**$ 4,551**	**$ 3,273**	**$ 2,332**	**$ 1,619**
		USA M$	**USA M$**	**USA M$**	**USA M$**	**USA M$**
United States	**Gustavson Associates**					
	Prepared March 14, 2008					
	Developed Producing	$ -	$ -	$ -	$ -	$ -
	Developed Non-Producing	$ 1,416	$ 1,080	$ 886	$ 759	$ 670
	Undeveloped					
	TOTAL PROVED USA	**$ 1,416**	**$ 1,080**	**$ 886**	**$ 759**	**$ 670**
	PROBABLE	$ 56,789	$ 29,358	$ 18,618	$ 13,040	$ 9,609
	TOTAL PROVED PLUS PROBABLE	**$ 58,205**	**$ 30,438**	**$ 19,503**	**$ 13,800**	**$ 10,279**
	POSSIBLE	$ 67,295.50	$ 31,720.40	$ 19,150.70	$13,077.10	$ 9,535.60
	TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE	**$ 125,501**	**$ 62,159**	**$ 38,654**	**$ 26,877**	**$ 19,815**
Exchange Rate Dec 31, 2007 (B. of Canada)	**$0.9801**					
COMPANY TOTALS	**TOTAL PROVED**	**$ 3,918**	**$ 2,736**	**$ 1,932**	**$ 1,346**	**$ 903**
Canadian M$	**TOTAL PROVED PLUS PROBABLE**	**$ 63,413**	**$ 34,384**	**$ 22,388**	**$ 15,857**	**$ 11,694**
	TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE	**$ 129,369**	**$ 65,473**	**$ 41,158**	**$ 28,674**	**$ 21,039**

c) Net Present Value of Future Net Revenue – After Income Taxes

Forecast Price as of December 31, 2007

Reserve Location

		CDN M$	CDN M$	CDN M$	CDN M$	CDN M$
	Discount rate %	0	5	10	15	20
Canada	**GLJ Petroleum Consultants Ltd.**					
	Prepared March 27, 2008					
	Developed Producing	$ 787	$ 558	$ 427	$ 344	$ 288
	Developed Non-Producing	$ 1,744	$ 1,119	$ 637	$ 258	$ (42)
	Undeveloped	$ -	$ -	$ -	$ -	$ -
	TOTAL PROVED CANADA	**$ 2,531**	**$ 1,677**	**$ 1,064**	**$ 602**	**$ 246**
	PROBABLE	$ 3,835	$ 2,874	$ 2,209	$ 1,730	$ 1,373
	TOTAL PROVED PLUS PROBABLE	**$ 6,366**	**$ 4,551**	**$ 3,273**	**$ 2,332**	**$ 1,619**
		USA M$	**USA M$**	**USA M$**	**USA M$**	**USA M$**
United States	**Gustavson Associates**					
	Prepared March 14, 2008					
	Developed Producing	$ -	$ -	$ -	$ -	$ -
	Developed Non-Producing	$ 923	$ 702	$ 574	$ 491	$ 433
	Undeveloped	$ -	$ -	$ -	$ -	$ -
	TOTAL PROVED USA	**$ 923**	**$ 702**	**$ 574**	**$ 491**	**$ 433**
	PROBABLE	$ 36,946	$ 17,574	$ 10,054	$ 6,214	$ 3,903
	TOTAL PROVED PLUS PROBABLE	**$ 37,869**	**$ 18,276**	**$ 10,628**	**$ 6,705**	**$ 4,336**
	POSSIBLE	$ 43,763	$ 19,475	$ 10,993	$ 6,974	$ 4,687
	TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE	**$ 81,632**	**$ 37,751**	**$ 21,621**	**$ 13,679**	**$ 9,023**
Exchange Rate Dec 31, 2007 (Bank of Canada)			**$0.9801**			
COMPANY TOTALS	**TOTAL PROVED**	**$ 3,436**	**$ 2,365**	**$ 1,627**	**$ 1,083**	**$ 670**
CDN M$	**TOTAL PROVED PLUS PROBABLE**	**$ 43,482**	**$ 22,463**	**$ 13,690**	**$ 8,904**	**$ 5,868**
	TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE	**$ 86,374**	**$ 41,551**	**$ 24,464**	**$ 15,739**	**$ 10,462**

d) Future Net Revenue by Production Group

As of December 31, 2007

RESERVES CAT.	FORECAST PRICES AND COSTS PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) CANADA MCdn $	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) USA MCdn $	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) CO. TOTAL MCdn$	UNIT VALUE ($/Mcf) CANADA Cdn $	UNIT VALUE ($/bbl) CANADA Cdn $	UNIT VALUE ($/Mcf) USA Cdn $
PROVED	**Light and Medium Crude Oil**	$ -	$ 328.29	**$ 328.29**			
	Heavy Oil	$ -	$ -	**$ -**			
	Natural Gas	$ 1,063.00	$ 557.44	**$ 1,620.44**	$ 0.71		$ 3.31
	Non-Conventional Oil and Gas Activities	$ -	$ -				
	Total Proved	**$ 1,063.00**	**$ 885.73**	**$ 1,931.10**			
PROBABLE	**Light and Medium Crude Oil**	$ -	$ 10,038.19				
	Heavy Oil		$ -				
	Natural Gas	$ 3,272.00	$ 9,465.28				$ 1.99
	Non-Conventional Oil and Gas Activities		$ -				
	Total Proved plus Probable	**$ 3,272.00**	**$ 19,503.47**	**$ 22,387.35**	$ 1.31		
TOTAL PROVED PLUS PROBABLE		**$ 4,335.00**	**$ 20,389.20**	**$ 24,318.45**			

Cdn $ to US $ Conversion (re bank of Canada December 31, 2007)

$ 0.9801

e) Table FP-5 (Canada)

December 31, 2007
Reconciliation of Company Gross Reserves
by Principal Product Type

	Total Oil			Light and Medium Oil			Heavy Oil			Natural Gas Liquids		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	+ Proved Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	+ Proved Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	+ Proved Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	+ Proved Probable (Mbbl)
December 31, 2006	0	0	0	0	0	0	0	0	0	0	0	0
Discoveries	0	0	0	0	0	0	0	0	0	4.7	1.6	6.3
Extensions*	0	0	0	0	0	0	0	0	0	0	18.8	18.8
Infill Drilling*	0	0	0	0	0	0	0	0	0	0	0	0
Improved Recovery*	0	0	0	0	0	0	0	0	0	0	0	0
Technical Revisions	0	0	0	0	0	0	0	0	0	0	0	0
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0	0	0	0	0	0	0
Production	0	0	0	0	0	0	0	0	0	0	0	0
December 31, 2007	0	0	0	0	0	0	0	0	0	4.7	20.4	25.1

	Total Gas			Conventional Natural Gas			Coal Bed Methane			BOE		
FACTORS	Proved (MMcf)	Probable (MMcf)	+ Proved Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	+ Proved Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	+ Proved Probable (MMcf)	Proved (Mboe)	Probable (Mboe)	+ Proved Probable (Mboe)
December 31, 2006	0	0	0	0	0	0	0	0	0	0	0	0
Discoveries	240.9	80.3	321.2	240.9	80.3	321.2	0	0	0	44.9	14.9	59.8
Extensions*	1584.1	1131.8	2715.9	1584.1	1131.8	2715.9	0	0	0	264	207.5	471.5
Infill Drilling*	0	0	0	0	0	0	0	0	0	0	0	0
Improved Recovery*	0	0	0	0	0	0	0	0	0	0	0	0
Technical Revisions	0	0	0	0	0	0	0	0	0	0	0	0
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0	0	0	0	0	0	0
Production	0	0	0	0	0	0	0	0	0	0	0	0
December 31, 2007	1825	1212.1	3037.1	1825	1212.1	3037.1	0	0	0	308.9	222.4	531.3

*The above change categories correspond to standards set out in the Canadian Oil and Gas Evaluation Handbook. For reporting under NI 51-101, reserve additions under Infill Drilling, Improved Recovery and Extensions should be combined and reported as "Extensions and Improved Recovery".

f) Table FP-5 (United States)

December 31, 2007
Reconciliation of Company Gross Reserves
by Principal Product Type

	Total Oil			Light and Medium Oil			Heavy Oil			Natural Gas Liquids		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	+ Proved Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	+ Proved Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	+ Proved Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	+ Proved Probable (Mbbl)
December 31, 2006	0	0	0	0	0	0	0	0	0	0	0	0
Discoveries	8.1	26.7	34.8	8.1	26.7	34.8	0	0	0	0	0	0
Extensions*	0	403.1	403.1	0	403.1	403.1	0	0	0	0	0	0
Infill Drilling*	0	0	0	0	0	0	0	0	0	0	0	0
Improved Recovery*	0	0	0	0	0	0	0	0	0	0	0	0
Technical Revisions	0	0	0	0	0	0	0	0	0	0	0	0
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0	0	0	0	0	0	0
Production	0	0	0	0	0	0	0	0	0	0	0	0
December 31, 2007	8.1	429.8	437.9	8.1	429.8	437.9	0	0	0	0	0	0

	Total Gas			Conventional Natural Gas			Coal Bed Methane			BOE		
FACTORS	Proved (MMcf)	Probable (MMcf)	+ Proved Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	+ Proved Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	+ Proved Probable (MMcf)	Proved (Mboe)	Probable (Mboe)	+ Proved Probable (Mboe)
December 31, 2006	0	0	0	0	0	0	0	0	0	0	0	0
Discoveries	168.6	211.6	380.2	168.6	211.6	380.2	0	0	0	36.2	62	98.2
Extensions*	0	4372.7	4372.7	0	4372.7	4372.7	0	0	0	0	1131.9	1131.9
Infill Drilling*	0	0	0	0	0	0	0	0	0	0	0	0
Improved Recovery*	0	0	0	0	0	0	0	0	0	0	0	0
Technical Revisions	0	0	0	0	0	0	0	0	0	0	0	0
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0	0	0	0	0	0	0
Production	0	0	0	0	0	0	0	0	0	0	0	0
December 31, 2007	168.6	4584.3	4752.9	168.6	4584.3	4752.9	0	0	0	36.2	1193.9	1230.1

*The above change categories correspond to standards set out in the Canadian Oil and Gas Evaluation Handbook. For reporting under NI 51-101, reserve additions under Infill Drilling, Improved Recovery and Extensions should be combined and reported as "Extensions and Improved Recovery".

g) Table FP-5 (Company Totals)

December 31, 2007
Reconciliation of Company Gross Reserves
by Principal Product Type

	Total Oil			Light and Medium Oil			Heavy Oil			Natural Gas Liquids		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	+ Proved Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	+ Proved Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	+ Proved Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	+ Proved Probable (Mbbl)
December 31, 2006	0	0	0	0	0	0	0	0	0	0	0	0
Discoveries	8.1	26.7	34.8	8.1	26.7	34.8	0	0	0	4.7	1.6	6.3
Extensions*	0	403.1	403.1	0	403.1	403.1	0	0	0	0	18.8	18.8
Infill Drilling*	0	0	0	0	0	0	0	0	0	0	0	0
Improved Recovery*	0	0	0	0	0	0	0	0	0	0	0	0
Technical Revisions	0	0	0	0	0	0	0	0	0	0	0	0
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0	0	0	0	0	0	0
Production	0	0	0	0	0	0	0	0	0	0	0	0
December 31, 2007	8.1	429.8	437.9	8.1	429.8	437.9	0	0	0	4.7	20.4	25.1

	Total Gas			Conventional Natural Gas			Coal Bed Methane			BOE		
FACTORS	Proved (MMcf)	Probable (MMcf)	+ Proved Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	+ Proved Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	+ Proved Probable (MMcf)	Proved (Mboe)	Probable (Mboe)	+ Proved Probable (Mboe)
December 31, 2006	0	0	0	0	0	0	0	0	0	0	0	0
Discoveries	409.5	291.36	701.4	409.5	291.36	701.4	0	0	0	81.1	76.9	158
Extensions*	1584.1	5504.5	7088.6	1584.1	5504.5	7088.6	0	0	0	264	1339.4	1603.4
Infill Drilling*	0	0	0	0	0	0	0	0	0	0	0	0
Improved Recovery*	0	0	0	0	0	0	0	0	0	0	0	0
Technical Revisions	0	0	0	0	0	0	0	0	0	0	0	0
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0	0	0	0	0	0	0
Production	0	0	0	0	0	0	0	0	0	0	0	0
December 31, 2007	1993.6	5795.86	7790	1993.6	5795.86	7790	0	0	0	345.1	1416.3	1761.4

*The above change categories correspond to standards set out in the Canadian Oil and Gas Evaluation Handbook. For reporting under NI 51-101, reserve additions under Infill Drilling, Improved Recovery and Extensions should be combined and reported as "Extensions and Improved Recovery".

DIVIDEND POLICY

The Company has not paid any dividends on its common shares. The Company may pay dividends on its common shares in the future if it generates profits. Any decision to pay dividends on common shares in the future will be made by the board of directors on the basis of the earnings, financial requirements and other conditions existing at such time.

GENERAL DESCRIPTION OF CAPITAL STRUCTURE

The authorized capital of the Company consists of three classes of shares: an unlimited number of common shares; an unlimited number of preferred shares designated as First Preferred Shares, issuable in series; and an unlimited number of preferred shares designated as Second Preferred Shares, issuable in series.

All of the common shares of the Company have equal voting rights, and none of the common shares are subject to any further call or assessment. There are no special rights or restrictions of any nature attaching to any of the common shares and they all rank pari passu each with the other as to all benefits which might accrue to the holders of the common shares. The common shares are not convertible into shares of any other class and are not redeemable or retractable.

The First Preferred Shares have priority over the common shares and the Second Preferred Shares with respect to the payment of dividends and in the distribution of assets in the event of a winding up of the Company. The Second Preferred Shares have priority over the common shares with respect to dividends and surplus assets in the event of a winding up of the Company.

As at the date hereof, 70,128,329 Common Shares were issued and outstanding. No First Preferred Shares or Second Preferred Shares have been issued.

MARKET FOR SECURITIES

Trading Price and Volume

The Company's common shares are listed for trading through the facilities of the TSXV and AMEX under the symbol "DEJ". The following table sets out, for the periods indicated, the high and low sales price and the volume of trading of the common shares of the Company on the TSXV during the periods indicated.

TSXV

Period	High ($)	Low ($)	Volume[1]
February 2008	1.80	1.20	3,421,400
January 2008	1.81	1.03	1,870,300
December 2007	1.64	1.35	1,048,000
November 2007	2.08	1.30	1,494,900
October 2007	2.35	1.78	1,155,400
September 2007	2.38	1.96	1,158,100
August 2007	2.63	1.50	2,160,000
July 2007	2.76	2.18	1,750,600
June 2007	2.49	2.18	1,638,400
May 2007	2.67	2.18	3,542,800
April 2007	3.28	2.47	4,816,400

Period	High ($)	Low ($)	Volume[(1)]
March 2007	2.71	2.07	4,039,300
February 2007	2.75	2.01	4,385,300
January 2007	2.77	2.17	3,335,300

DIRECTORS AND OFFICERS

The following table sets forth all current directors and executive officers as of the date of this AIF, with each position and office held by them in the Company and the period of service as such.

Name, Jurisdiction of Residence and Position [(1)]	Principal occupation or employment during the past 5 years	Number of Dejour Common Shares beneficially owned, directly or indirectly, or controlled or directed [(2)]
Robert L. Hodgkinson Vancouver, B.C., Canada Chairman and Chief Executive Officer. Director since May 18, 2004.	President of a private company, Hodgkinson Equities Corporation, which provides consulting services to emerging businesses in the petroleum resource industry. He is also a Director of the public companies, Royce Resources Corp. and Titan Uranium Inc.	4,222,500
Doug W. Cannaday Westminster, Colorado President and Chief Operating Officer. Director since July 14, 2004.	From 1999 until 2004, Mr. Cannaday also worked in Ecuador in the area of placer gold mining. During that time he was the President of Hampton Court Resources Ecuador S.A., a company located in the city of Quito.	610,620
Dr. Lloyd Clark [(3)] Delta, B.C. Director since February 7, 2005.	Independent consulting geological engineer since 1985. Consulting Geological Engineer for major mining companies, specializing in exploration of uranium, gold and base metal properties.	256,300
Archibald Nesbitt [(3)] Calgary, Alberta Director since November 24, 2005	Founder, senior officer and director of a number of publicly traded and private corporations including Gateway Gold Corporation, Southpoint Resources Ltd., Riverstone Resources Ltd. Bakbone Software Inc., Niblack Mining Corp., and Abacus Mining & Exploration Corp.	354,500
Dr. R. Marc Bustin Delta, B.C. Director August 30, 2005.	Professor of petroleum and coal geology in the Department of Earth Sciences at the University of British Columbia.	115,667
Craig Sturrock [(3)] Vancouver, B.C. Director since August 22, 2005.	Tax lawyer since 1971. Currently, he is a partner at Thorsteinssons LLP, and his practice focuses primarily on civil and criminal tax litigation.	250,000
Charles W.E. Dove Cochrane, Alberta. Director since August 17,2007	President of Dejour Energy (Alberta) Ltd. since April, 2006. From June 2002 to April 2006, President of Dove & Kay Exploration Ltd., a geophysical consulting & project management company.	375,000
Mathew Wong Burnaby, B.C. Chief Financial Officer since July 14, 2004.	Chartered Accountant worked at Ernst & Young LLP from 1995 to 2000. Since then, he worked as the Corporate Accounting Manager for Mitsubishi Canada Limited and CFO for Dejour Enterprise Ltd.	135,992

(1) Each director will serve until the next annual general meeting of the Company or until a successor is duly elected or appointed in accordance with the Notice of Articles and Articles of the Company and the *Business Corporations Act* (British Columbia).

(2) The number of common shares beneficially owned, directly or indirectly, or over which control or direction is exercised is based upon information furnished to the Company by individual directors and executive officers. Unless otherwise indicated, such common shares are held directly.

(3) Member of audit committee.

Control of Securities

The aggregate number of Dejour common shares held by the directors and senior officers is 6,230.579 being 8.9% of the issued and outstanding common shares as a March 21, 2008.

Board of Directors

Brief biographies for each member of Dejour's board of directors are set forth below:

Robert L. Hodgkinson: Mr. Hodgkinson was the Founder and Chairman of Optima Petroleum, which would drill 175 wells in Alberta and the Gulf of Mexico before merging to form Petroquest Energy, a NASDAQ traded company with a market capitalization of $470 million USD. Subsequently, he founded and was CEO of Australian Oil Fields, which would later merge to become $400 million Resolute Energy/Cardero Energy Inc. Mr. Hodgkinson was also a Vice-President and Partner of Canaccord Capital Corporation, and an early stage investor and original lease financier in Synenco Energy's Northern Lights Project, which today has 1.5 billion barrels oil in the reserve category in the Alberta Oil Sands. He brings an extensive network of relationships in the energy and venture capital markets to the Company.

Doug W. Cannaday: Mr. Cannaday has been a Director, Officer and controlling Principal for a number of exploration companies including Artesian Petroleum Corporation, Amador Resources Ltd., Seahawk Oil & Gas Ltd. and Lava Cap Resources Ltd. In 1999, Mr. Cannaday founded Riomin Resources S.A. in Ecuador. Subsequently, he served as a consultant for several Alberta oil and gas companies before joining Dejour Enterprises in 2003 as a consultant responsible for identifying oil and gas opportunities. He was appointed President and COO in December 2004.

Dr. Lloyd Clark: Dr. Lloyd Clark is one of the world's foremost geological engineers in his field. In addition to his numerous awards and distinctions, he has received 12 fellowships and research grants and published over 23 scientific papers on uranium exploration. For 9 years he served as Exploration Manager and Chief Geologist for Saskatchewan Mining Development Corporation (now Cameco) where he established the Exploration Branch, and oversaw a staff of up to 65 geologists. His group developed exploration techniques currently employed by numerous companies for uranium exploration. His team made the discovery of uranium at McArthur River, which is today the world's largest, most profitable and highest grade uranium mine. Dr. Clark also served for 6 years as Senior Research Geologist and Head of the Geochemical Research Division at Kennecott Exploration Inc. He also served for 10 years as a Professor of Geology and Geochemistry at McGill University, and 3 years as a pre-and post-doctoral research fellow at The Carnegie Institute in Washington, D.C. Geophysical Laboratory.

Archibald Nesbitt: Mr. Nesbitt brings over 25 years in the development and financing of junior resource and venture companies to Dejour Enterprises. These include Gateway Gold Corporation, Southpoint Resources Ltd., Riverstone Resources Ltd. and Bakbone Software Inc. His career in the resource business began in 1966 with his late father, John C. Nesbitt, focusing on the exploration for uranium near Uranium City, Saskatchewan where 20 years prior John C. Nesbitt discovered the Nesbitt Labine and Gunnar uranium mines. Mr. Nesbitt holds and an LLB. from University of Western Ontario and a B. Comm. Queens University.

Dr. R. Marc Bustin: Dr. Bustin has worked with Mobil Oil Canada, Gulf Canada Resources, ELF-Acquitaine (France), CSIRO (France) and CNRS (Australia). He has consulted and served as a director and technical advisor for a variety of small through large petroleum companies in Europe, Africa, North America and Asia, and was President of RMB Earth Science Consultants and Principal of CBM Solutions Ltd. With over 150 published scientific articles on fossil fuels, he is an Elected Fellow of the Royal Society of Canada, was a Professor of petroleum and coal geology in the Department of Earth Sciences at the University of British Columbia, has been an Associate Editor with the Canadian Society of Petroleum Geology Bulletin, Sedimentary Geology, International Journal of Coal Geology and the Canadian Journal of Earth Sciences. He is a member of the International Congress on the Carboniferous and Permian (ICCP), American Association of Petroleum Geologists (AAPG), The Society for Organic Petrology (TSOP) and Geological Society of America (GSA). He is also a past recipient of the A.L. Leverson memorial award from the AAPG, and received the Thiesson Medal from the International Committee for Coal Petrography in 2002 for his contributions to coal sciences/organic petrology. In 2003 he received the Sproule Award for contributions to the study of unconventional gas resources. Dr. Bustin has a PhD in geology from the University of British Columbia and is a registered Professional Geoscientist in BC.

Craig Sturrock: Mr. Sturrock has served as a director and founding member of various public and private companies. Admitted to the British Columbia Bar in 1969, he joined the firm Thorsteinssons LLP, tax lawyers in 1971. He served for 15 years as a tax lawyer and partner at Birnie, Sturrock & Company returning to Thorsteinssons as a Partner in 1989. His practice focuses primarily on civil and criminal tax litigation. His litigation experience includes both federal and provincial taxation statutes, with particular reference to criminal litigation and the Charter of Rights. He is an author and speaker for the Canadian and British Columbia Bar Associations, the Continuing Legal Education Society of British Columbia and the Canadian Tax Foundation. He is also a former member of the Board of Governors of the Canadian Tax Foundation.

Charles Dove: Beginning his 30 year career with Amoco Canada Petroleum Co. in 1978, Charles Dove brings an impressive background to his role as President of Dejour Energy (Alberta). Before joining Dejour, he held positions with CDEC Oil and Gas Ltd., Diamond Shamrock Exploration Ltd., Quintana Exploration Ltd. and Rustum Petroleum Ltd. where he discovered and developed oil and gas reserves in Western Canada. In 1989, Mr. Dove formed his own consulting firm working with several large Canadian oil and gas companies, co-founding and becoming a major shareholder in Innovative Energy Ltd., which was sold to Dennison Mines in 2001.

Mathew Wong: With over 11 years with Ernst & Young, GLT Network Inc. and Mitsubishi Canada, Mathew Wong brings an extensive background in public and private practice to the company. He boasts a strong corporate finance background in financial reporting and investment structuring, and is experienced in international tax, US GAAP reporting and internal control policies.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

To the knowledge of the Company, no director of the Company is, or has been in the last ten years, a director or executive officer of an issuer that, while that person was acting in that capacity, (a) was the subject of a cease trade order or similar order or an order that denied the issuer access to any exemptions under Canadian securities legislation, for a period of more than 30 consecutive days, (b) was subject to an event that resulted, after that person ceased to be a director or executive officer, in the issuer being the subject of a cease trade or similar order or an order that denied the issuer access to any exemption under Canadian securities legislation, for a period of more than 30 consecutive days, or (c) or within a year of that person ceasing to act in that capacity, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets. To the knowledge of the Company, in the past ten years, no director has become bankrupt, made a proposal under any legislation related to bankruptcy or insolvency, or was subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manger or trustee appointed to hold the assets of the director.

Conflicts of Interest

Certain of the Company's directors and officers serve or may agree to serve as directors or officers of other reporting companies or have significant shareholdings in other reporting companies and, to the extent that such other companies may participate in ventures in which the Company may participate, the directors of the Company may have a conflict of interest in negotiating and concluding terms respecting the extent of such participation. In the event that such a conflict of interest arises at a meeting of the Company's directors, a director who has such a conflict will abstain from voting for or against the approval of such participation or such terms and such director will not participate in negotiating and concluding terms of any proposed transaction. From time to time, several companies may participate in the acquisition, exploration and development of natural resource properties thereby allowing for their participation in larger programs, permitting involvement in a greater number of programs and reducing financial exposure in respect of any one program. It may also occur that a particular company will assign all or a portion of its interest in a particular program to another of these companies due to the financial position of the company making the assignment. Under the laws of the Province of British Columbia, the directors of the Company are required to act honestly, in good faith and in the best interests of the Company. In determining whether or not the Company will participate in a particular program and the interest therein to be acquired by it, the directors will primarily consider the degree of risk to which the Company may be exposed and its financial position at that time. See also "Description of the Business – Risk Factors".

AUDIT COMMITTEE INFORMATION

The Audit Committee Mandate and Composition is attached as Appendix “C” to this AIF.

AUDIT FEES

The following summarizes the amounts charged by the Company's independent auditors, Dale Matheson Carr-Hilton Labonte LLP, for the years ended December 31, 2007 and December 31, 2006.

	Year ended December 31, 2007	**Year ended December 31, 2006**
Audit Services Audit of the Corporation's annual consolidated financial statements	$40,000 (1)	$42,672
Audit Related Services	$6,800	$6,800
Tax Services Tax compliance and consulting	Nil	Nil

(1) Estimated fees.

LEGAL PROCEEDINGS

There are no material pending legal proceedings to which the Company is or is likely to be a party or which are known to the Company to be contemplated that are material to the business and affairs of the Company.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director, executive officer or principal shareholder of the Company, or any associate or affiliate of the foregoing, has had any material interest, direct or indirect, in any transaction within the three most recently completed financial years or during the current financial year prior to the date of this AIF that has materially affected or will materially affect the Company except for:

a) During 2007, the Company incurred a total of $187,500 (2006 - $136,670, 2005 - $100,000) in consulting fees and accrued US $34,195 (2006 – US $14,830, 2005 - Nil) of interest at 8% per annum related to US $400,000 of convertible debentures as discussed in Note 6, and $63,000 (2006 - $63,000) bonus payment to private companies controlled by the CEO of the Company.

b) During 2007, the Company incurred a total of $157,500 (2006 - $129,000, 2005 - $122,356) in consulting fees and accrued US $21,320 (2006 – US $14,830, 2005 - Nil) of interest at 8% per annum related to US $400,000 of convertible debentures as discussed in Note 6, and $63,000 (2006 - $63,000) bonus payment to the President or a private company controlled by the President of the Company. In April 2007, US $200,000 of convertible debentures was converted to 148,148 Units. Each Unit consists of one common share and one warrant, exercisable at US $1.50 per share, expiring on July 15, 2008. The Company also issued 9,254 Units to settle US $12,493 of accrued interest.

c) During 2007, the Company incurred $146,965 (2006 - $107,640, 2005 - $64,480) in consulting fees to a private company controlled by the CFO. The Company also accrued US $32,222 (2006 - US $14,830, 2005 - Nil) of interest at 8% per annum related to US $400,000 of convertible debentures as discussed in Note 6 to an individual related to the CFO. In November 2007, US $149,850 of convertible debentures was converted to 111,000 units. Each unit consists of one common share and one warrant, exercisable at US $1.50 per share, expiring on July 15, 2008.

d) During 2007, the Company's subsidiary ("DEAL") incurred a total of $172,750 (2006 - $105,625) in consulting fees to private companies controlled by the President of DEAL. The Company purchased Wild Horse Energy Ltd. for $354,880 from the President of DEAL. Wild Horse Energy Ltd. owned 10% shares of DEAL.

e) During 2007, the Company incurred $113,556 (2006 - $Nil) in consulting fees to a private company controlled by the vice-president of the Company.

f) During 2007, the Company incurred $45,500 (2006 - $Nil) in meeting attendance fees to the Company's independent directors.

g) Included in May 2007 private placements at $2.65 per Unit, 148,000 Units were issued to officers and directors. Included in November 2007 flow-through shares issuance at $1.82 per share, 680,000 flow-through shares were issued to officers and directors.

TRANSFER AGENTS AND REGISTRARS

The registrar and transfer agent of the common shares of the Company is Computershare Trust Company of Canada, 2nd Floor, and 510 Burrard Street, Vancouver, British Columbia, V6C 3B9.

MATERIAL CONTRACTS

Other than discussed herein, there are no material contracts, other than the contracts entered into in the ordinary course of business, that are material to the Company and that were entered into within the most recently completed financial year or before the most recently completed financial year, but are still in effect.

INTERESTS OF EXPERTS

Information of an economic (including economic analysis), scientific or technical nature in respect of the

Company’s oil and gas projects and properties is contained in this AIF based upon the two Reserves Reports, one dated March 25, 2008 prepared by GLJ Petroleum Consultants of Calgary, Alberta and one dated March 17,2008 prepared by Gustavson Associates LLC of Boulder, Colorado.

Dale Matheson Carr-Hilton Labonte LLP ("DMCL"), Chartered Accountants, of Vancouver, British Columbia, are the auditors of the Company. DMCL issued the auditors' report on the annual financial statements of the Company for the years ended December 31, 2007 and December 31, 2006, which are incorporated by reference into this AIF.

The author of the Reserves Reports and the auditors’ report have advised the Company that they beneficially own, directly or indirectly, less than one percent of the outstanding common shares.

DMCL has advised the Company that it is independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of British Columbia.

ADDITIONAL INFORMATION

Additional information relating to the Company may be found on SEDAR at www.sedar.com.

Additional information, including directors’ and officers’ remuneration and indebtedness, principal holders of the Company’s securities, and securities authorized for issuance under equity compensation plans, where applicable, is contained in the Company’s Information Circular for its most recent annual general meeting of securityholders that involved the election of directors.

Additional financial information is provided in the Company’s consolidated financial statements and management's discussion and analysis for the 12 months ended December 31, 2007.

APPENDIX "A"

FORM 51-101F2

REPORTS ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATORS

FORM 51-101F2
REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES
EVALUATOR OR AUDITOR

To the board of directors of Dejour Energy Ltd. (the "Company"):

1. We have prepared an evaluation of the Company's reserves data as at December 31, 2007. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2007, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2007, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - $M)			
			Audited	Evaluated	Reviewed	**Total**
GLJ Petroleum Consultants	March 28, 2008	Canada	-	$3,272	-	**$3,272**

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, March 31, 2008

Neil I. Dell, P. Eng.
Vice-President

8. FORM 51-101F2

REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES
EVALUATOR OR AUDITOR

This is the form referred to in item 2 of section 2.1 of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("*NI 51-101*").

1. Terms to which a meaning is ascribed in *NI 51-101* have the same meaning in this form.
2. The report on *reserves data* referred to in item 2 of section 2.1 of *NI 51-101*, to be executed by one or more *qualified reserves evaluators or auditors independent* of the *reporting issuer*, shall in all material respects be as follows:

Report on Reserves Data

To the Board of Directors of Dejour Energy (USA) Corp:

1. We have evaluated the Company's reserves and resources data as at 31 December 2007. The Company has gas and condensate reserves estimated as at 31 December 2007. The resources data consist of prospective and contingent oil and gas resources estimated as at 31 December 2007. The related future net revenue has not been estimated.

2. The reserves and resources data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves and resources data based on our evaluation.

We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves and resources data are free of material misstatement. An evaluation also includes preparing estimates of reserves and resources data in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated reserves of the Company evaluated by us as at 31 December 2007, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Report	Location of Reserves	Net Present Value of Future Net Revenue (thousands Canadian$, after income taxes, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
Letha C. Lencioni	Evaluation Report 31 March 2008	Various Basins, Colorado and Utah, USA	0	Proved: 574.2 Probable: 10,054.1 Possible: 10,992.5	0	Proved: 574.2 Probable: 10,054.1 Possible: 10,992.5

5. In our opinion, the reserves and resources data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. We express no opinion on the reserves and resources data that we reviewed but did not audit or evaluate; however, to our knowledge, all data were evaluated.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Letha C. Lencioni, Boulder, Colorado, USA, March 14, 2008

Total Future Net Revenue (Undiscounted)
as of December 31, 2007
Forecast Prices and Costs

Reserves Category	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Develop-ment Costs (M$)	Abandon-ment and Reclama-tion Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Income Taxes (M$)	Future Net Revenue After Income Taxes (M$)
Proved								
Developed Producing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Developed Non-Producing	2,420.0	487.1	487.4	25.0	5.0	1,415.6	492.7	922.9
Undeveloped	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Proved	2,420.0	487.1	487.4	25.0	5.0	1,415.6	492.7	922.9
Probable	96,160.0	19,230.2	5,413.5	14,666.9	59.9	56,789.4	19,843.0	36,946.4
Total Proved Plus Probable	98,580.0	19,717.3	5,900.9	14,691.9	64.9	58,205.0	20,335.7	37,869.3
Possible	103,170.0	20,632.2	5,843.0	9,361.9	37.4	67,295.5	23,532.6	43,762.9
Total Proved + Probable + Possible	201,750.0	40,349.5	11,744.0	24,053.8	102.4	125,500.4	43,868.3	81,632.2

APPENDIX "B"
FORM 51-101F3

Report of Management and Directors
on Reserves Data and Other Information

Management of Dejour (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at last day of the reporting issuer's most recently completed financial year, estimated using forecast prices and costs.

Independent qualified reserves evaluators or qualified reserves evaluators have evaluated the Company's reserves data. The report of the independent reserves evaluators is summarized in the Annual Information Form.

The board of directors of the Company has

(a) reviewed the Company's procedures for providing information to the independent evaluator;

(b) met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the qualified reserves evaluator to report without reservation .

(c) reviewed the reserves data with management and the independent qualified reserves evaluators.

The board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluators or qualified reserves auditors on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(signed) “Robert L. Hodgkinson”	(signed) “Douglas W. Cannaday”
Robert L. Hodgkinson Chairman & CEO	**Douglas W. Cannaday** Director & COO
(signed) “Marc Bustin”	(signed) “Charles E. Dove”
Marc Bustin Director	**Charles E. Dove** Director

APPENDIX "C"

DEJOUR ENTERPRISES LTD.

AUDIT COMMITTEE MANDATE

The primary function of the audit committee (the "Committee") is to assist the Board in fulfilling its financial oversight responsibilities by reviewing the financial reports and other financial information provided by the Company to regulatory authorities and Shareholders, the Company's systems of internal controls regarding finance and accounting and the Company's auditing, accounting and financial reporting processes. Consistent with this function, the Committee will encourage continuous improvement of, and should foster adherence to, the Company's policies, procedures and practices at all levels. The Committee's primary duties and responsibilities are to:

- Serve as an independent and objective party to monitor the Company's financial reporting and internal control system and review the Company's financial statements.

- Review and appraise the performance of the Company's external auditors.

- Provide an open avenue of communication among the Company's auditors, financial and senior management and the Board.

Composition

The Committee shall be comprised of three Directors as determined by the Board, the majority of whom shall be free from any relationship that, in the opinion of the Board, would interfere with the exercise of his or her independent judgment as a member of the Committee.

At least one member of the Committee shall have accounting or related financial management expertise. All members of the Committee that are not financially literate will work towards becoming financially literate to obtain a working familiarity with basic finance and accounting practices. For the purposes of the Company's Charter, the definition of "financially literate" is the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can presumably be expected to be raised by the Company's financial statements.

The members of the Committee shall be elected by the Board at its first meeting following the annual Shareholders' meeting. Unless a Chair is elected by the full Board, the members of the Committee may designate a Chair by a majority vote of the full Committee membership.

Meetings

The Committee shall meet a least twice annually, or more frequently as circumstances dictate. As part of its job to foster open communication, the Committee will meet at least annually with the Chief Financial Officer and the external auditors in separate sessions.

Responsibilities and Duties

To fulfill its responsibilities and duties, the Committee shall:

Documents/Reports Review

(a) Review and update this Charter annually.

(b) Review the Company's financial statements, MD&A and any annual and interim earnings, press releases before the Company publicly discloses this information and any reports or other financial information (including quarterly financial statements), which are submitted to any governmental body, or to the public, including any certification, report, opinion, or review rendered by the external auditors.

External Auditors

(a) Review annually, the performance of the external auditors who shall be ultimately accountable to the Board and the Committee as representatives of the Shareholders of the Company.

(b) Obtain annually, a formal written statement of external auditors setting forth all relationships between the external auditors and the Company, consistent with Independence Standards Board Standard 1.

(c) Review and discuss with the external auditors any disclosed relationships or services that may impact the objectivity and independence of the external auditors.

(d) Take, or recommend that the full Board take, appropriate action to oversee the independence of the external auditors.

(e) Recommend to the Board the selection and, where applicable, the replacement of the external auditors nominated annually for Shareholder approval.

(f) At each meeting, consult with the external auditors, without the presence of management, about the quality of the Company's accounting principles, internal controls and the completeness and accuracy of the Company's financial statements.

(g) Review and approve the Company's hiring policies regarding partners, employees and former partners and employees of the present and former external auditors of the Company.

(h) Review with management and the external auditors the audit plan for the year-end financial statements and intended template for such statements.

(i) Review and pre-approve all audit and audit-related services and the fees and other compensation related thereto, and any non-audit services, provided by the Company's external auditors. The pre-approval requirement is waived with respect to the provision of non-audit services if:

    i. the aggregate amount of all such non-audit services provided to the Company constitutes not more than five percent of the total amount of revenues paid by the Company to its external auditors during the fiscal year in which the non-audit services are provided;

    ii. such services were not recognized by the Company at the time of the engagement to be non-audit services; and

    iii. such services are promptly brought to the attention of the Committee by the Company and approved prior to the completion of the audit by the Committee or by one or more members of the Committee who are members of the Board to whom authority to grant such approvals has been delegated by the Committee.

Provided the pre-approval of the non-audit services is presented to the Committee's first scheduled meeting following such approval such authority may be delegated by the Committee to one or more independent members of the Committee.

Financial Reporting Processes

(a) In consultation with the external auditors, review with management the integrity of the Company's financial reporting process, both internal and external.

(b) Consider the external auditors' judgments about the quality and appropriateness of the Company's accounting principles as applied in its financial reporting.

(c) Consider and approve, if appropriate, changes to the Company's auditing and accounting principles and practices as suggested by the external auditors and management.

(d) Review significant judgments made by management in the preparation of the financial statements and the view of the external auditors as to appropriateness of such judgments.

(e) Following completion of the annual audit, review separately with management and the external auditors any significant difficulties encountered during the course of the audit, including any restrictions on the scope of work or access to required information.

(f) Review any significant disagreement among management and the external auditors in connection with the preparation of the financial statements.

(g) Review with the external auditors and management the extent to which changes and improvements in financial or accounting practices have been implemented.

(h) Review any complaints or concerns about any questionable accounting, internal accounting controls or auditing matters.

(i) Review certification process.

(j) Establish a procedure for the confidential, anonymous submission by employees of the Company of concerns regarding questionable accounting or auditing matters.

Other

Review any related-party transactions.

Composition of the Audit Committee

The following are the members of the Committee:

Craig Sturrock	Independent ①	Financially literate ①
Archibald Nesbitt	Independent ①	Financially literate ①
Lloyd Clark	Independent ①	Financially literate ①

① As defined by Multilateral Instrument 52-110 ("MI 52-110").

Relevant Education and Experience

Craig Sturrock has 34 years of experience in the practice of law. He is a partner of the law firm Thorsteinssons LLP, specializing in tax litigation. He was a former member of the Board of Governors of Canadian Tax Foundation. He has many years of experience working with clients and Canada Revenue Agency on financial and tax matters.

Archibald Nesbitt has 25 years of experience in the development and financing of junior resource venture companies and has served as director of several public companies. He holds LLB from the University of Western Ontario, and B.Comm from the Queens University.

Dr. Lloyd Clark received his B.E. in Geological Engineering and MSc from the University of Saskatchewan and his PhD in Geology from McGill University in 1959. He has over 50 years in uranium exploration and is one of the world's foremost geological engineers in his field. In addition to his numerous awards and distinctions, he has received 12 fellowships and research grants and published over 23 scientific papers on uranium exploration.

Audit Committee Oversight

At no time since the commencement of the Company’s most recently completed financial year was a recommendation of the Committee to nominate or compensate an external auditor not adopted by the Board of Directors.

Reliance on Certain Exemptions

At no time since the commencement of the Company's most recently completed financial year has the Company relied on the exemption in Section 2.4 of MI 52-110 (De Minimis Non-audit Services), or an exemption from MI 52-110, in whole or in part, granted under Part 8 of Multilateral Instrument 52-110.

Pre-Approval Policies and Procedures

The Committee has adopted specific policies and procedures for the engagement of non-audit services as described above under the heading "External Auditors".

Exemption in Section 6.1 of MI 52-110

The Company is relying on the exemption in Section 6.1 of MI 52-110 from the requirement of Parts 3 (Composition of the Audit Committee) and 5 (Reporting Obligations).