Madalena Ventures Inc.

Annual Information Form

Year Ended December 31, 2007

April 22, 2008

TABLE OF CONTENTS

ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
bbl	Barrel	Mcf	thousand cubic feet
bbls	Barrels	MMcf	million cubic feet
Mbbls	thousand barrels	Mcf/d	thousand cubic feet per day
MMbbls	million barrels	MMcf/d	million cubic feet per day
Mstb	1,000 stock tank barrels	MMbtu	million British Thermal Units
bbls/d	barrels per day	Bcf	billion cubic feet
bopd	barrels of oil per day	Tcf	trillion cubic feet
NGLs	natural gas liquids	Gj	gigajoule
STB	stock tank barrels		

Other

AECO	EnCana Corp.'s natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale
ARTC	Alberta Royalty Tax Credit
BOE or boe	barrel of oil equivalent of natural gas and crude oil on the basis of 1 BOE for 6 Mcf of natural gas
m3	cubic metres
MBOE	1,000 barrels of oil equivalent
Mstboe	1,000 stock tank barrels of oil equivalent
$000's or 000 $	Thousands of dollars
$mm	Millions of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade
psi	pounds per square inch

CONVERSIONS

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

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	bbls oil	6.293
feet	Metres	0.305
metres	Feet	3.281
miles	kilometres	1.609
kilometres	Miles	0.621
acres	Hectares	0.405
hectares	Acres	2.471
gigajoules	MMbtu	0.950

In this document, a boe conversion ratio of 6 Mcf = 1 bbl has been used throughout this document. Boe's may be misleading, particularly if used in isolation. A Boe conversion ratio of 6 Mcf to 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.

FORWARD LOOKING STATEMENTS

Certain statements contained in this Annual Information Form and in certain documents incorporated by reference into this Annual Information Form, constitute forward-looking statements. These statements relate to future events or the Company's future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Company believes that the expectations reflected in those forward looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form, as the case may be. The Company does not intend, and does not assume any obligation, to update these forward-looking statements, except as required pursuant to applicable securities laws.

In particular, this Annual Information Form and the documents incorporated by reference herein contain forward-looking statements pertaining to the following:

- the quantity of reserves;
- oil and natural gas production levels;
- capital expenditure programs;
- projections of market prices and costs;
- supply and demand for oil and natural gas;
- productive capacity of wells;
- timing of tie-in operations;
- expectations regarding the Company's ability to raise capital and to continually add to reserves through acquisitions, exploitation and development; and
- treatment under government regulatory and taxation regimes.

The Company's actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Annual Information Form:

- volatility in market prices for oil and natural gas;
- liabilities and risks inherent in oil and natural gas operations;
- uncertainties associated with estimating reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems;
- whether farm-in and farm-out opportunities result in agreement;
- effect of environmental legislation;
- fluctuations in foreign exchange, interest rates and stock markets; and
- the other factors discussed under "**Risk Factors**".

These factors should not be considered exhaustive. Other than if required by applicable securities laws, the Company does not undertake any obligation to publicly update or revise any forward-looking statements.

CERTAIN DEFINITIONS

In this Annual Information Form, the following words and phrases have the following meanings:

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

"**Common Shares**" or "**common shares**" means the common shares of Madalena as presently constituted;

"**Company**" or "**Madalena**" means Madalena Ventures Inc., a company created under the laws of the Province of British Columbia, and continued under the laws of the Province of Alberta;

"**GLJ**" means GLJ Petroleum Consultants Ltd.;

"**GLJ Report**" means the report of GLJ dated March 12, 2008 evaluating the crude oil, natural gas liquids and natural gas reserves of the Company as at December 31, 2007;

"**Gross**" or "**gross**" means:

(a) in relation to the Company's interest in production and reserves, its "Company gross reserves", which are the Company's interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Company;

(b) in relation to wells, the total number of wells in which the Company has an interest; and

(c) in relation to properties, the total area of properties in which the Company has an interest.

"**Net**" or "**net**" means:

(a) in relation to the Company's interest in production and reserves, the Company's interest (operating and non-operating) share after deduction of royalties obligations, plus the Company's royalty interest in production or reserves;

(b) in relation to wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells; and

(c) in relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company.

"**NGL**" or "**NGLs**" means natural gas liquid or natural gas liquids;

"**NI 51-101**" means National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities;

"**NI 51-102**" means National Instrument 51-102 - Continuous Disclosure Obligations; and

"**TSXV**" means the TSX Venture Exchange, Inc.

MADALENA VENTURES INC.

General

Madalena was created under the laws of the Province of British Columbia on September 14, 2001, on the amalgamation of Madalena Gold Company and Corsair Minerals Inc., as part of a statutory arrangement (the "**Arrangement**") under the former *Issuer Act* (British Columbia) involving Pacific Genesis Technologies, Madalena Gold Company, and Corsair Minerals Inc. On September 30, 2004 Madalena Ventures Inc. amalgamated with a wholly owned subsidiary, RMS Medical Systems Research (B.C.) Ltd., and continued as Madalena Ventures Inc.

On August 22, 2006 the Company completed a further plan of arrangement (the "**2006 Arrangement**") whereby the mineral exploration assets, and marketable securities related to the mineral exploration assets, were transferred to Great Bear Resources Inc. ("**GBR**"), with each shareholder of Madalena receiving one common share of GBR for every 15 common shares of Madalena. The purpose of the 2006 Arrangement was to separate the mineral exploration business in GBR so that GBR could carry on the mineral exploration business, and Madalena could focus on its' recently developed oil and gas exploration business. The Company was then continued from the province of British Columbia to the province of Alberta on September 26, 2006.

The Company's Common Shares are listed on the TSXV under the symbol "MVN".

The Company's principal office is located at 200, 441 - 5th Avenue S.W., Calgary, Alberta, T2P 2V1, and the Company's registered office is located at Suite 1400, 350 - 7th Avenue S.W., Calgary, Alberta, T2P 3N9.

Inter-corporate Relationships

The Company has no investments in any other companies, partnerships or trusts. The Company's Canadian oil and gas exploration, development and production operations are carried on through a joint venture with Profound Energy Inc. ("**Profound**") (formerly Cork Exploration Inc.), and Burlington Resources Ltd. Two members of the board of directors of Madalena were members of the board of directors of Cork Exploration Inc. until it merged with Profound during 2007.

GENERAL DEVELOPMENT OF THE BUSINESS

Madalena is an independent, Canadian-based, international upstream oil and gas company whose main business activities include exploration, development and production of crude oil, natural gas liquids and natural gas. The Company has exploration and production operations in Canada, Tunisia, and South America.

Three Year History

2005

In 2005, the Company was actively involved in the exploration and development of certain mineral exploration properties, which were subsequently disposed under the terms of the 2006 Arrangement. In June of 2005, the common shares of the Company were listed for trading on the CNQ trading and quotation system.

In late 2005, Madalena made strategic changes to its board of directors, in order to position itself to take advantage of domestic and international oil and gas exploration and development opportunities. Management believes the current board of directors contains individuals with significant oil and gas experience both domestically and internationally. See "*Directors and Officers of the Company*".

2006

In 2006, Madalena focused its efforts on building an international oil and gas exploration and development company. Madalena announced new directors to its board, attracted a new management team and consultants with both domestic and international oil and gas experience, and completed the 2006 Arrangement which distributed the mineral exploration business to the shareholders.

On January 27, 2006, the Company announced an agreement with Cork Exploration Inc, to participate in the drilling of four wells in the Edson area of Alberta, Canada, by paying 25% of drilling, abandonment or completion costs, to earn 12.5% in 12 sections, and on May 8, 2006, the Company announced a second agreement with Cork Exploration Inc., to participate in a six well program in the Brazeau area of Alberta, Canada, by paying 33.335% of drilling, abandonment or completion costs, to earn interests varying between 17% to 24% in 8.5 sections, and an option to participate in two additional sections.

On May 23, 2006, the Company entered into a seismic option agreement with Storm Ventures International Inc. ("**Storm**") on the Hammamet offshore exploration block containing over 1.1 million acres in the Pelagian basin offshore Tunisia. The option agreement gives Madalena the right to participate in the drilling of a test well on the block, in exchange for paying 30% of the costs of a 2-D and 3-D seismic program. If Madalena exercises the option it will pay 30% of the costs of the test well to earn a 15% working interest and the right to participate in all further development of the block. The 3-D seismic program has now been completed and the Company is in the process of evaluating the seismic data.

On June 8, 2006, the Company entered into a second seismic option agreement with Storm on the Remada Sud onshore exploration block containing over 1.2 million acres in the prospective Ghadames basin of southern Tunisia. The option agreement gives Madalena the right to participate in the drilling of two test wells on the block, in exchange for paying 30% of the costs of a 2-D seismic program. If Madalena exercises its option to drill the first test well it will pay 30% of the costs of the test well to earn a 15% working interest in approximately half the block or a 7.5% interest in the entire block as well as the right to participate in all further development of the block. The 2-D seismic program has now been completed and evaluated, and the Company has exercised its option to participate in the drilling of the first test well. The well was spud on March 28, 2008 and is expected to reach target depth within the second quarter of 2008.

During fiscal 2006, Madalena raised $27,124,200 to fund its exploration and development opportunities, consisting of (i) a brokered private placement of 12,000,000 common shares at a price of $0.50 per share for total proceeds of $6,000,000, which closed March 2, 2006, (ii) a non-brokered private placement of 1,000,000 units at a price of one dollar per unit for total proceeds of $1,000,000. Each unit consisted of one common share and one-half of a share purchase warrant, all of which warrants have expired or have been exercised as of the date hereof, and (iii) a brokered private placement, issuing 25,155,250 units at a price of $0.80 per unit for gross proceeds of $20,124,200. Each unit consisted of one common share and one-half of a share purchase warrant, all of which have expired or have been exercises as of the date hereof.

2007

In February of 2007, the Company received final listing approval from the TSX Venture Exchange. The Common Shares were listed and posted for trading on Friday, February 16, 2007 under the trading symbol "MVN".

In June of 2007, the Company appointed Mr. James K. Wilson to the Board of Directors. Mr. Wilson brings international oil and gas, public company reporting, and financial reporting experience to the Board of Madalena.

In July 2007, the Company announced its intention to participate in the drilling of an exploration well on the Remada Sud onshore exploration block in southern Tunisia following a review of the newly acquired seismic. The Company also announced the commencement of the offshore 3-D seismic program on the Hammanet offshore exploration block in the Pelagian Basin offshore Tunisia.

In March of 2007 the Company announced that it had been granted approval to operate as a branch in Argentina under the name Madalena Ventures Inc. (Sucursal Argentina), ("**MVISA**"), and in August 2007, the Company announced that it had received governmental approval, from the National Energy Secretariat, registering the Company as an operator in Argentina.

In September 2007, the Company executed a letter of intent with Hidrocarburos del Neuquen Sociedad Anonime ("**HIDENESA**"), the Neuquen Provincial Hydrocarbon Company, and received approval for a work commitment to pursue exploration activities on the Cortadera exploration block in the province of Neuquen, Argentina. The joint venture participants in the block are MVISA 70%, HIDENESA 10%, and Estrella Servicios Petroleros S.A. ("**Estrella**") 20%. This joint venture opportunity carries an initial three year exploration term with a work commitment of $US 2.5 million in exploration expenditures on the block, including seismic and the drilling of at least one exploration well. Madelena and Estrella are proportionately responsible for the costs during the initial exploration term. Upon encountering commercial production on the block a development plan would be implemented with a 12% royalty payable to the province of Neuquen and a concession term of 25 years, with an option to request an additional 10 year extension.

In October of 2007, the Company announced that MVISA executed letters of intent with HIDENESA and received approval for a work commitment to pursue exploration activities on two new exploration blocks in the province of Neuquen, Argentina, known as the Curamhuele and Coiron Amargo blocks. Madelena had an initial minimum 70% participating interest in the blocks and HIDENESA has a 10% participating interest. Roch SA had the option to participate for 20% which they elected to take on February 29, 2008. The joint venture for these new blocks carries an initial three year exploration term with work commitments of $US 3.0 million for the Curamhuele block and $US 5.0 million for the Coiron Amargo block. Upon encountering commercial production on a block, a development plan will be implemented with a 12% royalty payable to the province of Neuquen and a concession term of 25 years, with an option to request an additional 10 year extension. In addition there is a 1% overriding royalty reserve to a third party on the Curamhuele block.

PRINCIPAL PROPERTIES

Madalena's strategy is to create value through the generation of a balanced portfolio of high quality oil and gas assets in proven hydrocarbon areas characterized by competitive fiscal terms and significant development potential.

Principal Properties

Canada (Brazeau and Edson Areas of Alberta)

All of Madalena's reserves and production come from non-operated properties in the Brazeau and Edson Areas of Alberta. The Brazeau area of Alberta is located south of Drayton Valley and the Edson area is located approximately 100 miles west of Edmonton.

Madalena has working interests of between 20% and 25% in six non-operated wells in Brazeau, Madalena obtains natural gas and natural gas liquids from its interests in four gross gas wells producing from the Rock Creek, Notikewin, Shunda and Fernie formations, and light oil production from one gross oil well in the Peco formation. One gas well is shut in.

Madalena has a 12.5% working interest in one producing gas well and one shut in gas well in the Edson area of Alberta which produces from the Rock Creek formation.

Madalena’s share of production from the Brazeau and Edson properties averaged 47 boe/d for the fourth quarter of 2007. The GLJ Report attributes proved plus probable reserves of 157 MBOE to Madalena’s working interests in Brazeau and Edson. The GLJ Report attributes proved reserves of 111 MBOE to Madalena’s working interests in Brazeau and Edson.

Future development plans by the operator in Brazeau call for the completion of a new zone in a producing gas well, and the drilling of a new well to which reserves have been assigned in the Rock Creek and Notikewan zones. Future development plans by the operator in Edson include bringing one well on production in 2008.

Tunisia (Remada Sud and Hammamet)

Madalena has entered into seismic option agreements with Storm (the operator of the properties) for the onshore Remada Sud and offshore Hammamet exploration blocks in Tunisia. The seismic option agreements give Madalena the right to participate in the drilling of two exploration wells on the Remada Sud block, and one exploration well on the Hammamet block in exchange for Madalena paying for 30% of the costs of 2-D and 3-D seismic acquisition and evaluation programs on the blocks. If Madalena participates in drilling these test wells it will earn up to 15% interests in the concessions.

The Remada Sud exploration block is located in the Ghadames basin in the southern portion of Tunisia along the border of Libya. The exploration block covers 1.2 million acres of exploration property. The 2-D seismic acquisition program was completed in Remada Sud during the second quarter 2007 providing further delineation of structures identified by the 2-D seismic data shot during 2005. In June of 2007 the Company announced its intention to participate in the first test well and in January of 2008 the Company formally exercised its election to participate in the first test well earning a 15% working interest in approximately half of the block (600,000 acres) and the option to participate in a second test well on the block. The drilling of the TT-2 well in Remada Sud commenced on March 28, 2008.

The Hammamet exploration block is located in shallow waters off the north eastern tip of Tunisia in the Gulf of Hammament in the Mediterranean Sea. The block includes approximately 1.1 million acres of exploration property. 2-D and 3-D seismic programs were completed in the third quarter 2007 to highlight existing leads and prospects in the offshore Hammamet area. Interpretation of the seismic data continued into the first quarter 2008**.**

No reserves have been assigned in connection with the Remada Sud or the Hammamet properties given the early stage of development in both these areas. The Company and its operator have the right to explore and appraise the Tunisian assets but do not have the right to produce from the properties until such time as reserves are determined to be commercial. Exploration, appraisal and development of crude oil and natural gas reserves is speculative and involves a significant degree of risk. There is no guarantee that exploration or appraisal of the Tunisian blocks will lead to a commercial discovery or, if there is a discovery, that the Company will be able to realize such reserves. See "*Risk Factors*".

Argentina (Cortadera, Curamhuele, and Coiron Amargo)

In November of 2007, Madalena executed joint venture agreements with HIDENESA on three concessions granted by the Province of Neuquen in Argentina, South America. The three blocks, Cortadera, Curamhuele, and Coiron Amargo are located in the Neuquen producing basin in the Province of Neuquen and contain approximately 278,000 acres of exploration area.

The Cortadera block covers an area of approximately 124,000 acres and is situated along the western thrust belt of the Neuquen basin in the middle portion of the province of Nuequen, approximately 700 miles south and west of Buenos Aires. Madalena has a 70% interest in the block which carries a three year exploration term with a work commitment of $2.5 million US dollars which includes exploration costs, seismic and the drilling of at least one exploration well. Madalena and its 20% working interest partner, Estrella, pay 100% of the costs during the exploration phase. If reserves are discovered in commercial quantities production will be subject to a 12% royalty payable to the province of Neuquen. HIDENESA is responsible for its 10% share of the costs incurred in the development and production phase.

The Curamhuele block covers an area of approximately 56,000 acres and is situated along the east side of a north south trending fault in the middle portion of the province of Nuequen, approximately 650 miles south and west of Buenos Aires and approximately 50 miles north of the Cortadera block. Madalena has a 70% interest in the block which carries a three year exploration term with a work commitment of $3.0 million US dollars which includes exploration costs, seismic and the drilling of at least one exploration well. Madalena and its 20% working interest partner, Roch, pay 100% of the costs during the exploration phase. If reserves are discovered in commercial quantities production will be subject to a 12% royalty payable to the province of Neuquen. HIDENESA is responsible for its 10% share of the costs incurred in the development and production phase.

The Coiron Amargo block covers an area of approximately 100,000 acres and is situated along the east side of the Neuquen block, approximately 650 miles southwest of Buenos Aires and approximately 75 miles east of the Cortadera block. Madalena has a 70% interest in the block which carries a three year exploration term with a work commitment of $5.0 million US which includes exploration costs, seismic and the drilling of at least one exploration well. Madalena and its 20% working interest partner, Roch, pay 100% of the costs during the exploration phase. If reserves are discovered in commercial quantities production will be subject to a 12 royalty payable to the province of Neuquen. HIDENESA is responsible for its 10% share of the costs incurred in the development and production phase.

No reserves have been assigned to the Argentine blocks given their early stage of development. The Company and its operators have the right to explore and appraise the Argentine blocks but do not have the right to produce from the properties until such time as reserves are determined to be commercial. Exploration, appraisal and development of crude oil and natural gas reserves is speculative and involves a significant degree of risk. There is no guarantee that exploration or appraisal of the Argentine blocks will lead to a commercial discovery or, if there is a discovery, that the Company will be able to realize such reserves. See "*Risk Factors*".

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated March 12, 2008. The effective date of the statement is December 31, 2007 and the preparation date of the statement is March 6, 2008.

Disclosure of Reserves Data and Other Information

The reserves data set forth below (the "**Reserves Data**") is based upon an evaluation by GLJ of the Reserves in association with Madalena's assets and has an effective date of December 31, 2007. The GLJ Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101 and the COGE Handbook. The Reserves Data summarizes the oil, liquids and natural gas reserves associated with Madalena's assets and properties and the net present values of future net revenue for these Reserves using forecast prices and costs as at December 31, 2007. The Reserves Data conforms with the requirements of NI 51-101. Madalena engaged GLJ to provide evaluations of Proved Reserves and Proved plus Probable Reserves.

All evaluations of future revenue are stated after the deduction of future income tax expenses (unless otherwise noted in the tables), royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenue contained in the following tables does not necessarily represent the fair market value of the Reserves associated with Madalena's assets and properties. There is no assurance that the forecast price and cost assumptions contained in the GLJ Report will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are summarized in the notes to the following tables. The recovery and reserves estimates for Madalena's assets and properties described herein are estimates only and there is no guarantee that the estimated Reserves will be recovered. The actual Reserves for Madalena's assets and properties may be greater or less than those calculated.

The Report of Management and Directors on Oil and Gas Disclosure (on Form 51-101F3) and the Report on Reserves Data by GLJ (on Form 51-101F2) are included in this AIF. See "Form 51-101F2 - Report on Reserves Data by GLJ Petroleum Consultants Ltd." and, "Form 51-101F3 - Report of Management and Directors on Oil and Gas Disclosure" attached hereto as Schedules A and B, respectively.

Summary of Oil and Gas Reserves and Net Present Values of Future Net Revenue At December 31, 2007

Forecast Prices and Costs

Reserves Category	Natural Gas Gross (MMcf)	Natural Gas Net (MMcf)	NGL Gross (Mbbl)	NGL Net (Mbbl)	Light/Medium Crude Oil Gross (Mbbl)	Light/Medium Crude Oil Net (Mbbl)	Oil Equivalent Gross (Mbbl)	Oil Equivalent Net (Mbbl)
Proved								
Developed Producing	196	167	10	7	23	19	65	54
Developed Non-Producing	126	118	6	5	0	0	27	25
Undeveloped	87	80	4	3	0	0	19	17
Total Proved	409	364	20	16	23	19	111	95
Probable	180	157	9	6	7	6	46	39
Total Proved Plus Probable	589	521	29	22	30	25	157	134

Net Present Values of Future Net Revenue

Reserves Category	Before and after Income Taxes Discounted at (%/year) 0% $000's	5% $000's	10% $000's	15% $000's	20% $000's	Unit Value Before Income Tax Discounted at 10%/year $/boe
Proved						
Producing	2,321	1,930	1,656	1,455	1,303	30.87
Developed Non-Producing	733	575	464	383	323	18.66
Undeveloped	262	173	113	71	40	6.77
Total Proved	3,316	2,678	2,232	1,909	1,666	23.46
Probable	1,309	791	520	366	273	13.48
Total Proved Plus Probable	4,625	3,469	2,752	2,275	1,939	20.58

Total Future Net Revenue
(Undiscounted)
At December 31, 2007

Forecast Prices and Costs

Reserves Category	Revenue (000 $)	Royalties (Includes ARTC) (000 $)	Operating Costs (000 $)	Develop-ment Costs (000 $)	Other Income (000 $)	Well Abandonment and Reclamation Costs (000 $)	Future Net Revenue Before Income Taxes (000 $)	Income Taxes (000 $)	Future Net Revenue After Income Taxes (000 $)
Total Proved Reserves	6,696	974	1,933	380	0	92	3,316	0	3,316
Total Proved Plus Probable Reserves	9,642	1,429	3,030	449	0	109	4,625	0	4,625

Future Net Revenue
by Production Group
at December 31, 2007

Forecast Prices And Costs

Future Net Revenue Before Income Taxes (discounted at 10%/year)

Reserves Category	Production Group	(000 $)	$/boe
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	-	-
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding solution gas from oil wells)	2,232	23.46
Proved plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	-	-
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding solution gas from oil wells)	2,752	20.58

Summary Of Pricing And Inflation Rate Assumptions
at December 31, 2007

Forecast Prices And Costs

GLJ Petroleum Consultants
Natural Gas Price Forecast
Effective January 1, 2008

		Alliance						
		Spot						
Year	AECO-C Spot Then Current (Cdn$/MMbtu)	Then Constant 2008 ($/MMbtu)	Then Current ($/MMbtu)	ARP ($/MMbtu)	Aggregator ($/MMbtu)	Alliance ($/MMbtu)	Inflation Rates (1) (%/year)	Exchange Rate (2) ($US/$CDN)
2008	6.75	6.53	6.53	6.44	6.17	5.92	2	1
2009	7.55	7.18	7.33	7.24	6.99	6.68	2	1
2010	7.60	7.09	7.37	7.31	7.11	6.73	2	1
2011	7.60	6.95	7.37	7.31	7.11	6.83	2	1
2012	7.60	6.81	7.37	7.31	7.11	6.83	2	1
2013	7.60	6.68	7.37	7.31	7.11	6.83	2	1
2014	7.80	6.72	7.57	7.51	7.30	7.02	2	1
2015	7.97	6.74	7.74	7.67	7.47	7.18	2	1
2016	8.14	6.75	7.91	7.84	7.63	7.34	2	1
2017	8.31	6.76	8.08	8.01	7.79	7.51	2	1
2018+	8.48	6.76	8.24	8.17	7.95	7.66	2	1

Notes:

(1) Inflation rates for forecasting pricing and costs.
(2) Exchange rates used to benchmark reference prices in this table.

GLJ Petroleum Consultants
Crude Oil and Natural Gas Liquids
Price Forecast
Effective January 1, 2008

			NYMEX WTI Near Month Futures Contract Crude Oil at Cushing Oklahoma		Light, Sweet Crude Oil (40 API, 0.3%S) at Edmonton		Alberta Natural Gas Liquids (Then Current Dollars			
Year	Inflation %	Bank of Canada Average Noon Exchange Rate $US/$Cdn	Constant 2008 $US/bbl	Then Current $US/bbl	Constant 2008 $Cdn/bbl	Then Current $Cdn/bbl	Spec Ethane $Cdn/bbl	Edmonton Propane $Cdn/bbl	Edmonton Butane $Cdn/bbl	Edmonton Pentanes Plus $Cdn/bbl
2008	2.0	1.000	92.00	92.00	91.10	91.10	22.73	58.30	72.88	92.92
2009	2.0	1.000	86.28	88.00	85.39	87.10	25.49	55.74	69.68	88.84
2010	2.0	1.000	80.74	84.00	79.87	83.10	25.66	53.18	66.48	84.76
2011	2.0	1.000	77.27	82.00	76.42	81.10	25.66	51.90	64.88	82.72
2012	2.0	1.000	75.76	82.00	74.92	81.10	25.66	51.90	64.88	82.72
2013	2.0	1.000	74.27	82.00	73.46	81.10	25.66	51.90	64.88	82.72
2014	2.0	1.000	72.81	82.00	72.01	81.10	26.35	51.90	64.88	82.72
2015	2.0	1.000	71.39	82.00	70.60	81.10	26.94	51.90	64.88	82.72
2016	2.0	1.000	70.00	82.02	69.23	81.12	27.52	51.91	64.89	82.74
2017	2.0	1.000	70.00	83.66	69.25	82.76	28.11	52.97	66.21	84.42
2018+	2.0	1.000	70.00	+2.0%/yr	69.25	+2.0%/yr	-	Escalate at 2.0% per year		

Weighted average historical prices realized by the Company for year ended December 31, 2007 were $7.16/Mcf for natural gas, $74.38/bbl for crude oil, and $60.19/bbl for natural gas liquid.

On October 25, 2007, the Alberta government announced the Alberta New Royalty Framework, ("**NRF**"). The reserves related tables in this report do not reflect these changes as the government has not yet clarified certain aspects of the new royalty calculations. The new changes which would most effect the Madalena's reserve outlook are to do with the Deep Gas Royalty Adjustment. The sensitivity to the Company's proved plus probable reserves through application of the maximum royalty effect of the NRF would be to reduce the net boe's after royalties from 134 MBOE to 129 MBOE, a reduction of 5 mboe, or just under 4%. Working interest proved plus probable reserves would remain at 157 MBOE's.

Reconciliation of Gross Reserves by Principal Product Type

The following table summarizes the changes in reserves from December 31, 2006(1) to December 31, 2007(1):

Forecast Prices And Costs

	Light & Medium Crude Oil			NGLs			Natural Gas			Total boe		
FACTORS	**Proved (Mbbls)**	**Probable (Mbbls)**	**Proved Plus Probable (Mbbls)**	**Proved (Mbbls)**	**Probable (Mbbls)**	**Proved Plus Probable (Mbbls)**	**Proved (MMcf)**	**Probable (MMcf)**	**Proved Plus Probable (MMcf)**	**Proved (boe)**	**Probable (boe)**	**Proved Plus Probable (boe)**
December 31, 2006	23	12	35	28	17	46	672	425	1,096	164	99	2.63
Technical Revisions	4	(5)	(1)	(6)	(8)	(14)	(206)	(244)	(450)	(37)	(53)	(90)
Discovery	0	0	0	0	0	0	0	0	0	0	0	0
Extension	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
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	(5)	0	(5)	(2)	0	(2)	(57)	0	(57)	(16)	0	(16)
December 31, 2007	23	7	30	20	9	29	409	180	590	111	46	157

Historical Undeveloped Reserves – Forecast Prices and Costs

The following tables set forth the proved undeveloped reserves and the probable undeveloped reserves, each by product type, attributed to the Company's assets for the years ended December 31, 2007, 2006 and 2005 and, in the aggregate, before that time based on forecast prices and costs.

Proved Undeveloped Reserves

Year	Light and Medium Crude Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior to 2005	0	0	0	0	0	0
2005	0	0	0	0	0	0
2006	0	0	87	87	4	4
2007	0	0	0	0	0	0

Probable Undeveloped Reserves

Year	Light and Medium Crude Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior 2005	0	0	0	0	0	0
2005	0	0	0	0	0	0
2006	0	0	35	35	2	2
2007	0	0	0	0	0	0

Proved Undeveloped Reserves

The Company generally attributes proved undeveloped reserves under the following categories:

1. Wells which are budgeted and scheduled to be drilled in the near future and are located between existing wells such that there is a high degree of certainty that the reservoir is present and producible in these locations.

2. Enhanced recovery recognition on pools which the Company expects to be put under EOR within the next year and/or incremental recovery from recently implemented EOR projects.

The Company does not carry proved undeveloped reserves for long periods of time unless there is a good reason (such as the above) for not putting these reserves on production in the short term. In fact, where there is sufficient economic justification, the Company will often take steps to accelerate production from gas caps and secondary zones. These steps involve early gas cap blowdown when it does not significantly impact oil recovery and dually completing or twinning wells for secondary zones.

Probable Undeveloped Reserves

Probable undeveloped reserves are, for the most part, attributed to step-out drilling locations, re-completion and tie-ins that are anticipated to proceed in the near term but do not meet the required confidence factor to be booked as proved.

Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex. It requires judgment and making decisions based on available geological, geophysical, engineering and economic data. Estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserves estimates contained herein are based on current production forecasts, geological evaluation, engineering data, prices and economic conditions. The Reserves associated with the Madalena assets have been evaluated by GLJ, an independent engineering firm. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the Reserves.

As circumstances change and additional data becomes available, Reserves estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions. Revisions to Reserves estimates can arise from changes in, among other things, year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

Future Development Costs

The following table outlines the forecast for future development costs associated with Madalena assets and properties for the reserves categories noted below, calculated on an undiscounted and a discounted (10%) basis:

	Future Development Costs Forecast Prices and Costs (000 $)	
Year	Proved Reserves	Proved Plus Probable Reserves
2008	20	83
2009	326	333
2010	-	-
2011	-	-
2012	-	-
Remainder	34	34
Total (Undiscounted)	380	449
Total (Discounted at 10%)	320	385

Future development costs are capital expenditures which will be required in the future for Madalena to convert Proved Undeveloped Reserves and Probable Reserves to Proved Developed Producing Reserves.

On an ongoing basis, Madalena intends to use internally generated cash flow from operations, debt (where deemed appropriate) and new equity issues (if available on favourable terms) to finance its capital expenditure program. When financing corporate acquisitions, Madalena may also assume certain future liabilities.

The future development costs are capital expenditures required in the future for Madalena to convert Proved Undeveloped Reserves and probable reserves to Proved Developed Producing Reserves. The undiscounted development costs are $380,000 for Proved Reserves and $449,000 for Proved Plus Probable Reserves (in each case based on forecast prices and costs).

On an ongoing basis, Madalena will use internally generated cash flow from operations, debt and new equity issues if available on favourable terms to finance its capital expenditure program. The cost of funding is not expected to have any effect on disclosed reserves or future net revenue nor make the development of a property uneconomic for the Company.

Other Oil and Gas Information

Landholdings

The following table sets forth the developed and undeveloped landholdings of Madalena as at December 31, 2007:

Location	Total Developed Undeveloped & Right to Earn (Acres) Gross(1)	Net(2)	Developed (Acres) Gross(1)	Net(2)	Undeveloped (Acres) Gross(1)	Net(2)	Right to Earn (Acres) Gross(1)	Net(2)
Tunisia(3):								
Remada Sud	1,200,000	180,000			600,000	90,000	600,000	90,000
Hammamet	1,100,000	165,000					1,100,000	165,000
Argentina:								
Cortadera	124,000	86,800			124,000	86,800		
Curamhuele	56,000	39,200			56,000	39,200		
Coiron Amargo	100,000	70,000			100,000	70,000		
Canada:								
Edson	1,920	267	1,920	267	-	-	-	-
Brazeau	6,080	1,487	4,480	1,044	1,600	443	-	-
	2,588,000	541,754	6,400	1,311	881,600	286,443	1,700,000	255,000

Notes
(1) Gross means the total gross acres in which the Company has an interest.
(2) Net means the total gross acres in which the Company has an interest multiplied by the working interest owned by the Company.
(3) The Company has seismic option agreements in Tunisia which provide it with the option to participate in drilling to earn an interest in the area. See "*Principal Properties*".

No reserves have been assigned to the total acreage for Tunisia or Argentina, as both of these areas are in the preliminary phases of development. In Canada, reserves 6,400 gross and 1.311 net acres have been assigned proved or probable reserves.

Oil and Natural Gas Wells

The following table sets forth the number and status of wells in which Madalena has a working interest and which are producing or which Madalena considers to be capable of production as at December 31, 2007:

	Producing Wells				Shut-in Wells(1)			
	Oil		Natural Gas		Oil		Natural Gas	
Location	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Edson	0	0	1	0.1	0	0	1	0.1
Brazeau	1	0.2	4	0.9	0	0	2	0.5
Total	1	0.2	5	1.0	0	0	3	0.6

Note:
(1) "**Shut-in**" wells refers to wells that have encountered, and are capable of producing, crude oil or natural gas but which are not producing due to the timing of the well completion and/or tie in which is anticipated to occur in 2008.

Properties With No Attributed Reserves

The following table sets forth Madalena's undeveloped land position as at December 31, 2007:

	Gross		Net	
Location	Acres	Sections	Acres	Sections
Tunisia, North Africa	2,300,000	3,593.7	345,000	539.1
Argentina, South America	280,000	437.5	196,000	306.2
Alberta, Canada	1,600	2.5	443	0.7
Total	2,581,600	4,033.7	541,443	846.0

In Tunisia there are no work commitments established in the seismic option agreements. However during 2007, the Company committed to drilling the first test well in the Remada Sud block at a cost of $2,100,000 US. These funds were advanced to the operator in early March of 2008 and the well started drilling March 28, 2008.

In Argentina, the Company has agreed to work commitments on the Cortadera, Curamhuele, and Coiron Amargo blocks in the amount of $10,500,000 over a three year term.

Forward Contracts and Marketing

The Company does not have any forward contracts or hedges currently in place.

Additional Information Concerning Abandonment Costs

Madalena estimates well abandonment costs on an area by area basis using historical costs and supplemented by current industry costs and changes in regulatory requirements. Estimated costs of abandonment were included in the GLJ Report as a deduction in determining future net revenue. The total estimated abandonment costs in respect of proved reserves using forecast prices is $92,000 undiscounted ($37,000 using a 10% discount rate). 100% of such amounts were deducted as abandonment costs in estimating future net revenue of the Company in respect of proved reserves as disclosed above. No allowance for salvage value was included in these costs. The table below indicates the expected timing of well abandonment costs for the Company.

The Company uses industry historical costs to estimate its abandonment costs when available. The costs are estimated on an area by area basis. The industry's historical costs are used when available. If representative comparisons are not readily available, an estimate is prepared based on the various regulatory abandonment requirements. The Company has 9 net wells for which it expects to incur abandonment costs.

The following table sets forth abandonment costs deducted in the estimation of the Company's future net revenue:

Forecast Prices and Costs (Total Proved Plus Probable) ($000s)

Year	Abandonment Costs (Undiscounted)
2008	0
2009	0
2010	0
Thereafter	109
Total Undiscounted	109
Total Discounted @ 10%	31

Tax Horizon

Depending on levels of production, commodity prices, acquisitions and capital expenditures, Madalena will not begin paying current income taxes in the foreseeable future.

Costs Incurred

The following table summarizes capital expenditures (net of asset retirement costs and office equipment) related to the Company's activities for the year ended December 31, 2007 ($000s):

	Canada	Tunisia	Argentina
Property acquisition costs			
Proved properties	-	-	-
Undeveloped properties	-	-	1,755,405
Exploration costs	260,174	2,387,887	171,054
Development costs	834,368	-	-
Total	1,094,542	2,387,887	1,926,459

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which the Company participated in Canada during the year ended December 31, 2007:

	Exploration		Development	
	Gross	Net	Gross	Net
Light and Medium Oil	-	-	-	-
Natural Gas	-	-	1	0.2
Service	-	-	-	-
Dry	1	0.1	-	-
Total:	1	0.1	1	0.2

The Company did not participate in any exploratory or development wells in Tunisia or in Argentina during the year ended December 31, 2007. However, on March 28, 2008 the Company participated in one gross, 0.15 net exploratory well on the Remada Sud block in Tunisia. See "*Principal Properties*".

See "*Principal Properties*" for a description of the Company's exploration and development plans for the Canadian properties. In Tunisia the terms of our option agreements do not specify specific exploration or development commitments, however the Company has participated in the Remada Sud TT-2 well which spud March 28, Madalena's share of the cost of the well is approximately $2.1 million US. On completion of drilling and testing, the operator and the Company will evaluate completion or abandonment alternatives.

In Argentina Madalena has agreed to work commitments of approximately $10.5 million US over the next three years. In 2008 the Company intends to complete seismic exploration programs on two of the exploration blocks and will look to drill at least one exploration well on each of the blocks over the next three years. The Company anticipates drilling at least one and perhaps two of these wells by the end of 2008.

Production Estimates

The following table sets out the volume of the Company's gross working interest production estimated for the year ended December 31, 2008 as evaluated by GLJ which is reflected in the estimate of future net revenue disclosed in the tables contained under "Disclosure of Reserves Data and Other Information".

Forecast Prices and Costs

Total Proved

	Light and Medium Oil *(Bbls/d)*	Natural Gas *(Mcf/d)*	Natural Gas Liquids *(Bbls/d)*	BOE *(BOE/d)*
Edson	0	7	0	2
Brazeau	13	100	5	35
Other Properties	-	-	-	-
Total Proved	13	107	5	37

Total Proved Plus Probable

	Light and Medium Oil *(Bbls/d)*	Natural Gas *(Mcf/d)*	Natural Gas Liquids *(Bbls/d)*	BOE *(BOE/d)*
Edson	0	23	1	5
Brazeau	13	103	5	36
Other Properties	-	-	-	-
Total Proved plus Probable	13	126	6	41

Production History

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below:

	Quarter Ended 2007			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production[(1)]				
Light and Medium Crude Oil (Bbls/d)	18	8	28	-
Gas (Mcf/d)	136	180	155	161
NGLs (Bbls/d)	6	7	8	6
Combined (Boe/d)	47	45	62	33
Average Price Received				
Light and Medium Crude Oil ($/Bbl)	77.07	78.66	71.42	-
Gas ($/Mcf)	6.32	6.04	8.31	8.03
NGLs ($/Bbls)	65.82	65.26	58.81	50.41
Combined ($/Boe)	56.75	48.38	60.88	48.60
Royalties Paid (Net of ARTC)				
Light and Medium Crude Oil ($/Bbls)	10.98	3.97	4.30	-
Gas ($/Mcf)	1.82	2.41	0.80	6.29
NGLs ($/Bbls)	1.08	1.22	0.64	1.06
Combined ($/Boe)	13.88	7.60	5.74	7.35
Operating & Transportation Expenses ($/Boe)				
Light and Medium Crude Oil ($/Bbls)	4.05	3.20	5.16	-
Gas ($/Mcf)	4.74	8.57	5.08	14.47
NGLs ($/Bbls)	2.34	3.63	1.76	3.63
Combined ($/Boe)	11.13	15.40	12.00	18.10
Netback Received ($/Boe)[(2)]				
Light and Medium Crude Oil ($/Bbls)	62.04	71.49	61.96	-
Gas ($/Mcf)	(0.24)	(4.94)	2.43	(12.73)
NGLs ($/Bbls)	62.40	60.41	56.41	45.72
Combined ($/Boe)	31.74	25.38	43.14	23.15

Notes:

(1) Before deduction of royalties.
(2) Netbacks are calculated by subtracting royalties and operating and transportation costs from revenues.

The following table indicates the Company's average daily production from its important fields for the year ended December 31, 2007:

	Light and Medium Crude Oil (Bbls/d)	Gas (Mcf/d)	NGLS (Bbls/d)	BOE (BOE/d)
Brazeau	13.6	141.0	6.05	43.2
Edson	-	16.6	0.81	3.58
Total Alberta	13.6	157.6	6.86	46.8

The Company's production for the year ended December 31, 2007 was 60% natural gas and natural gas liquids and 40% light and medium crude oil.

The Company expects that rights to explore, develop and exploit zero net acres of its undeveloped land holdings will expire by December 31, 2008, a portion of which may be continued by drilling. Madalena is considering whether or not to drill or submit application to continue selected portions of the above acreage.

For the twelve months ended December 31, 2007, approximately 53% of the Company's gross revenue was derived from petroleum and natural gas production.

DIVIDEND POLICY

The board of directors of the Company will determine the timing, payment and amount of future dividends, if any, that may be paid by the Company from time to time based upon, among other things, the cash flow, results of operations and financial condition of the Company, the need for funds to finance ongoing operations and other business considerations as the board of directors considers relevant.

DESCRIPTION OF CAPITAL STRUCTURE

The Company is authorized to issue an unlimited number of Common Shares without nominal or par value. As at April 21, 2008, there were 111,743,702 Common Shares issued and outstanding. In addition, as at such date, there were an aggregate of 10,180,000 Common Shares reserved for issuance upon the exercise of outstanding options to purchase common shares, and an aggregate of 12,577,625 Common Shares reserved for issuance upon the exercise of outstanding warrants to purchase common shares.

Each Common Share entitles its holder to receive notice of and to attend all meetings of the shareholders of the Company and to one vote at such meetings. The holders of Common Shares are, at the discretion of the board of directors of the Company and subject to applicable legal restrictions, entitled to receive any dividends declared by the board of directors on the Common Shares, subject to prior satisfaction of all preferential rights attached to all shares of other classes of the Company ranking in priority to the Common Shares. The holders of Common Shares are entitled to share equally in any distribution of the assets of the Company upon the liquidation, dissolution, bankruptcy or winding-up of the Company or other distribution of its assets among its shareholders for the purpose of winding-up its affairs, subject to prior satisfaction of all preferential rights attached to all shares of other classes of the Company ranking in priority to the Common Shares.

MARKET FOR SECURITIES

The common shares of the Company trade on the TSXV under the symbol "MVN". The common shares were listed and began trading on the TSXV on February 16, 2007. Prior to February 16, 2007, the common shares of the Company were listed for trading on the Canadian Trading and Quotation System ("**CNQ**").

The following table sets forth the price range and volume of the Common Shares as reported by the TSXV from February 16, 2007 to December 31, 2007 and by CNQ from January 1, 2007 until the Company was listed for trading on the TSXV.

2007	**High**	**Low**	**Volume**
January	0.79	0.60	2,156,000
February	0.89	0.72	1,418,000
March	0.80	0.56	1,294,000
April	0.74	0.55	1,899,000
May	0.74	0.60	1,360,000
June	0.67	0.52	1,365,000
July	0.71	0.54	1,609,000
August	0.66	0.43	1,152,000
September	0.77	0.52	1,427,000
October	0.76	0.60	974,000
November	0.70	0.48	1,100,000
December	0.55	0.42	790,000

ESCROWED SECURITIES

As of the date hereof, 4,545,900 Common Shares issued and outstanding at the date of listing on the TSX Venture Exchange remain subject to escrow in accordance with the rules of the TSX Venture Exchange under a value security escrow agreement (the "**Escrow Agreement**") among the shareholders, the Company, and Computershare Trust Company of Canada, as trustee. The following table provides a summary of the percentage of original shares, number of shares and the dates of release of the original common shares subject to escrow.

%	Number of common shares released	Release Date
10%	757,650	At listing date – February 16, 2007
15%	1,136,475	6 months – August 16, 2007
15%	1,136,475	12 months – February 16, 2008
15%	1,136,475	18 months – August 16, 2008
15%	1,136,475	24 months – February 16, 2009
15%	1,136,475	30 months – August 16, 2009
15%	1,136,475	36 months – February 16, 2010

DIRECTORS AND OFFICERS

The name and place of residence of each director and officer, the offices held by each in the Company, and the principal occupation of the directors and officers, the period served as director and the number of securities of the Company owned by such individuals as at April 21, 2008 is as follows:

Name, Address and Position	Principal Occupation for the Previous 5 Years	Director Since	Number of Common Shares
Ken Broadhurst Alberta, Canada Director / President / Chief Executive Officer	Currently the President and Chief Executive Officer of Madalena; September 2001 to February 24, 2006, President and Chief Executive Officer of privately owned Era Oil & Gas Corp. and Egypt Production Interest Corp.	February 24, 2006	1,870,000
Dwayne Warkentin Alberta, Canada Director / Senior Vice President / Chief Operating Officer	Currently Chief Operating Officer of Madalena. Prior thereto, Chief Operating Officer and Vice President, Operations at Antrim Energy Inc., from 1999 to February 24, 2006.	February 24, 2006	1,600,000
Greg Ford Alberta, Canada Chief Financial Officer	Currently Vice-President, Finance and Chief Financial Officer of Madalena. Executive Director of Ernst & Young LLP from February 1999 until joining the Company.	N/A	300,000
Ray Smith California, USA Director / Chairman (5) (6) (7)	Currently Chairman of the Board of Madalena and Cruiser Oil and Gas Ltd., and a Director of True Energy Trust, both public oil and gas exploration companies. Formerly Chairman and CEO of Cork Exploration Ltd., Rydal Energy, New Cache Petroleum, Corsair Energy, and Meridian Energy Corp.	October 12, 2005	4,971,500
Mike Lock Alberta, Canada Director(4) (5) (6)	Currently President of Upsilon Holdings Ltd., a privately owned consulting company and consultant to Oil Exco Ltd.	December 29,2005	510,000(1)
Ving Woo Alberta, Canada Director(4) (7)	Currently director of Madalena, and formerly a Director of Cork Exploration Inc., a public oil and gas company. Formerly Vice President, Engineering for Meridian Energy Corp. from September 2002 until March 2005. Formerly Vice President, Engineering for Corsair Exploration Inc. from July 1999 until April 2002. Formerly Vice President, Engineering for New Cache Petroleum from February 1996 until February 1999.	March 10, 2006	725,000
J.G. (Jeff) Lawson Alberta, Canada Director(5)	Currently Managing Director, Head of Calgary Investment Banking, Blackmont Capital Inc. Formerly a Partner with Burnet, Duckworth & Palmer LLP.	June 2, 2006	Nil

Name, Address and Position	Principal Occupation for the Previous 5 Years	Director Since	Number of Common Shares
James K. Wilson Director(4)	Currently Vice-president Finance and Chief Financial Officer of Grizzly Resources Inc., a private oil and gas company, and Director of Ironhorse Oil & Gas Inc., and Rock Energy Inc. Formerly Vice-President Finance and Chief Financial officer for a number of public companies including Grey Wolf Exploration Inc., Maxx Petroleum Ltd. and Chauvco Resources International Ltd.	June 18, 2007	43,000

Notes:

(1) Ms. Kathryn Lock, the spouse of Mike Lock, holds directly 500,000 Common Shares.
(2) 200,000 Common Shares are held by Mr. Mike Lock in trust for one minor and three adult children.
(3) 100,000 Common Shares are held in Mr. Woo's CIBC Wood Gundy RRSP account.
(4) Member of the Audit Committee.
(5) Member of the Corporate Governance Committee.
(6) Member of the Compensation Committee.
(7) Member of the Reserves Committee.

The directors and officers of the Company own, directly or indirectly, or control or exercise direction over 10,519,500 common shares, representing 9.41% of the issued and outstanding common shares.

Each director of the Company holds office from the time elected until the next annual meeting of the Company at which time they shall retire but, if qualified, shall be eligible for re-election. All officers of the Company, in the absence of agreement to the contrary, shall be subject to removal by resolution of the board of directors of the Company at any time, with or without cause.

Each of Ken Broadhurst, Dwayne Warkentin and Greg Ford devote their full time and attention to the business affairs of the Company.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

To our knowledge, and other than as set forth below, no director or executive officer of the Company: (i) is, or has been in the last 10 years, a director, chief executive officer or chief financial 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 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 securities legislation, for a period of more than 30 consecutive days, or (c) within a year of that person ceasing to act in that capacity, became 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; (ii) has, within the last 10 years, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangements or compromises with creditors, or had a receiver or receiver manager or trustee appointed to hold his assets; or (iii) has been subject to: (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority, or (b) any other penalties or sanctions imposed by a court or regulatory body.

Mr. Mike Lock was Vice President of Land for Big Bear Exploration Inc. ("**Big Bear**"), which filed under the *Companies Creditor Arrangement Act* (Canada) in March of 1999. Mr. Lock left employment with Big Bear in November of 1999.

Jeff Lawson has been a director of BakBone Software Incorporated ("**BakBone**") since 2000. In October 2004, BakBone announced that, in conjunction with a change of accountants, it would not be in a position to file its quarterly report on Form #10-Q for the September 30, 2004 period and consequently, on December 4, 2004, each of the Alberta, British Columbia and Ontario Securities Commissions issued cease trade orders against BakBone to the effect that all trading in the securities of BakBone cease until it has filed its financial statements in accordance with

Canadian securities legislation. These orders remain outstanding at present date, and will continue in effect until such time as BakBone has filed all of its outstanding financial statements.

No director or officer of the Company, or a shareholder holding a sufficient number of securities of the Company to affect materially the control of the Company, has been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority or any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

There are potential conflicts of interest to which the directors and officers of the Company will be subject in connection with the operations of the Company. In particular, certain of the directors and officers of the Company are involved in managerial and/or director positions with other oil and gas companies whose operations may, from time to time, be in direct competition with those of the Company or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of the Company. See "*Directors and Officers*". Conflicts, if any, will be subject to the procedures and remedies available under the ABCA. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the ABCA.

HUMAN RESOURCES

The Company currently employs five full-time employees and two consultants. The Company intends to add additional professional and administrative staff as the needs arise.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no outstanding legal proceedings material to the Company to which the Company is a party or in respect of which any of its respective properties are subject, nor are there any such proceedings known to be contemplated. In addition, there were no penalties or sanctions imposed against the Company by a court relating to securities legislation or by a securities regulatory authority during the 2007 financial year, no other penalties or sanctions imposed by a court or regulatory body against the Company that would likely be considered important to a reasonable investor in making an investment decision, and no settlement agreements entered into by the Company with a court relating to securities legislation or with a securities regulatory authority during the 2007 financial year.

TRANSFER AGENT AND REGISTRAR

Computershare Trust Company of Canada, at its principal offices in Calgary, Alberta is the transfer agent and registrar of the Common Shares of the Company.

RISK FACTORS

Investors should carefully consider 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, any existing reserves the Company may have at any particular time, 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 continue 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.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Company makes acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as the Company's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Company. The integration of acquired business may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of, so that the Company can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Company, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Company.

Operational Dependence

Other companies operate some of the assets in which the Company has an interest. As a result, the Company will have 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.

Competition

The petroleum industry is competitive in all its phases. The Company will compete 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 those of 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. Competition may also be presented by alternate fuel sources.

Regulatory

Oil and natural gas operations (exploration, production, pricing, 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 intended business, financial condition and results of operations. In order to conduct oil and gas operations, the Company will require 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" 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. See "*Industry Conditions*".

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 and will subject the Company to comply with the new regulatory framework announced on March 10, 2008 by the Federal Government which is intended to force large industries to reduce emissions of greenhouse gases, in addition to 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 will be 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. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Kyoto Protocol or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Company. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Company and its operations and financial condition. 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 may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. The Company may also be 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.

The prices of oil and natural gas prices may be volatile and 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 expected net production revenue and a reduction in its oil and gas acquisition, development and exploration activities. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Company. These factors include economic conditions, in the United States and Canada, the actions of the Organization of Petroleum Exporting Countries, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Company's carrying value of its proved reserves, borrowing capacity, revenues, profitability and cash flows from operations.

Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

In addition, bank borrowings available to the Company may, in part, be determined by the Company's borrowing base. A sustained material decline in prices from historical average prices could reduce the Company's borrowing base, therefore reducing the bank credit available to the Company which could require that a portion, or all, of the Company's bank debt be repaid.

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 have negatively impacted Madalena's operating entities production revenues. Further material increases in the value of the Canadian dollar would exacerbate this 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.

An increase in interest rates could result in a significant increase in the amount the Company pays to service debt, which could negatively impact the market price of the Company Shares.

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, it will affect the Company's ability to expend the necessary capital to replace its reserves or to maintain its production. 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 terms acceptable to the Company.

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 articles nor its by-laws 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 and the Company may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. 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 natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth herein 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, the Company's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. 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 reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Company intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and has not been updated and thus does not reflect changes in the Company's reserves since that date.

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 maintains 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. 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 will not have insurance to protect against the risk from terrorism.

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 Licences 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.

Dividends

The Company has not paid any dividends on its outstanding shares. Payment of dividends in the future will be dependent on, among other things, the cash flow, results of operations and financial condition of the Company, the need for funds to finance ongoing operations and other business considerations as the board of directors of the Company considers relevant.

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 properties 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.

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 ABCA. See "*Directors and Officers*" and "*Conflicts of Interest*".

Reliance on Key Personnel

The Company's success depends in large measure on certain key personnel. The loss of the services of such key personnel could have a material adverse affect on the Company. The contributions of the existing management team to the immediate and near term operations of the Company are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Company will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Company.

Tunisian Risk Factors

Political Risks

Tunisia has experienced relative prosperity and stability under the leadership over the past two decades. Notwithstanding this relative stability, in the past, Tunisia has been affected by extremist Islamic militant activity. Tunisian authorities have implemented anti terrorism policies and security precautions. By law, parties organized on the basis of religion, region, race or language is forbidden. Despite this, there are groups in Tunisia dedicated to turning the country into an Islamic republic. The Tunisian government has taken steps to prevent the Islamic militants struggle in neighbouring Algeria from affecting Tunisia by increasing its military presence along the Tunisia/Algeria border, imposing visa restrictions and imposing strict controls on local militants. Tunisia is bordered by both Algeria and Libya. Both countries have experienced periods of civil, political and military unrest and Libya has been the subject of international sanctions; future unrest in any of the neighbouring countries could affect Tunisia.

Requirement for Permits and Licenses

The operations of the Company require a license, permits and in some cases renewals of existing licenses and permits from the government of Tunisia (named the licensing authority in the conventions). The Company believes that it currently holds or has applied for all necessary licenses and permits to carry on the activities, which it is currently conducting under applicable laws and regulations in respect of its properties, and also believes that it is complying in all material respects with the terms of such licenses and permits. However, the ability of the Company to obtain, sustain or renew such licenses and permits on acceptable terms is subject to change in regulations and policies and to the discretion of the applicable government.

Legal Systems

The jurisdictions in which the Company operates may have less developed legal systems than more established economies, which may result in risks such as:

(i) effective legal redress in the courts of such jurisdictions, whether in respect of a breach of law or regulation, or, being difficult to obtain;

(ii) a higher degree of discretion on the part of governmental authorities;

(iii) the lack of judicial or administrative guidance on interpreting applicable rules and regulations;

(iv) inconsistencies or conflict between and within various laws, regulations, decrees, orders or resolutions; or

(v) relative inexperience of the judiciary courts in such matters;

in certain jurisdictions the commitment of local businesspeople, government officials and agencies and the judicial system to abide by legal requirements and negotiated agreements may be more uncertain, creating particular concerns with respect to licenses and agreements for businesses. These may be susceptible to revision or cancellation and legal redress may be uncertain or delayed. There can be no assurance the joint ventures, licenses, license applications or other legal arrangements will not be adversely affected by the actions of government authorities and the effectiveness of an enforcement of such arrangements in these jurisdictions cannot be assured. As a result of a limited infrastructure present in Tunisia, the land titles systems are not developed to the extent found in many more developed nations. Although the Company believes that it has good title to its oil and gas properties, there is little it can do to control this risk.

Argentina Risk Factors

Political Risk

During the early months of 2002, business, economic and financial conditions in Argentina deteriorated, although there have been some recent improvements. The deterioration accelerated when Argentina defaulted on certain indebtedness following devaluation of the country's currency, periodic non-convertibility of the Argentinean peso, exchange controls, administered prices for crude oil and natural gas at below North American market levels, newly-proposed taxes and other developments. Conditions have now improved as evidenced by the exchange rate of the Argentinean peso, which has been reasonably stable since 2003. The Company acquired the Argentinean properties after this time. However, there can be no assurance that economic and financial conditions in Argentina will not suffer similar deterioration in the future.

Fluctuations in Foreign Currency Exchange Rates

Crude oil sales in Argentina are denominated in US dollars, natural gas sales are denominated in Argentinean Pesos and operating and capital costs are generally incurred in Argentinean Pesos and US dollars. Fluctuations in the US dollar, Argentinean Peso and exchange rates may cause a negative impact on revenue and costs and could have a material adverse impact on the Company's operations.

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation, and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada and Alberta each of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these controls or regulations will affect the Company's operations in a manner materially different than they would affect other oil and gas companies of similar size. All current legislation is a matter of public record and the Company is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing - Oil and Natural Gas

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to the markets, the value of refined products, the supply/demand balance, and other contractual terms. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires the approval of the Governor in Council.

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day), must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires the approval of the Governor in Council.

The government of Alberta regulates the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements, and market considerations.

Pipeline Capacity

Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market natural gas production. In addition, the pro-rationing of capacity on the inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, United States of America, and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada United States Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price subject to an exception with respect to certain voluntary measures which only restrict the volume of exports; and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum or maximum export or import price requirements, provided, in the case of export price requirements, prohibition in any circumstances in which any other form of quantitative restriction is prohibited, and in the case of import-price requirements, such requirements do not apply with respect to enforcement of countervailing and anti-dumping orders and undertakings.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector by 2010 and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, which is important for Canadian natural gas exports.

Provincial Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection, and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas liquids, sulphur, and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery, and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays, and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. Royalty holidays and reductions would reduce the amount of Crown royalties paid by oil and gas producers to the provincial governments and would increase the net income and funds from operations of such producers. However, the trend in recent years has been for provincial governments to eliminate, amend or allow such incentive programs to expire without renewal, and consequently few such incentive programs are currently operative.

The Canadian federal corporate income tax rate levied on taxable income is 22.1% effective January 1, 2007 for active business income including resource income. With the elimination of the corporate surtax effective January 1, 2008 and other rate reductions introduced in the October 2007 Economic Statement and Notice of Ways and Means Motion, 2006 Federal Budget, the federal corporate income tax rate will decrease to 15% in five steps: 19.5% on January 1, 2008, 19% on January 1, 2009; 18% on January 1, 2010, 16.5% on January 1, 2011 and 15% on January 2012.

Alberta

In Alberta, companies are granted the right to explore, produce and develop petroleum and natural gas resources in exchange for royalties, bonus bid payments and rents. Currently, the amount of royalties that are payable is influenced by the oil production, density of the oil, and the vintage of the oil. Originally, the vintage classified oil as "new oil" and "old oil" depending on when the oil pools were discovered. If the pool was discovered prior to March 31, 1974 it is considered "old oil", if it was discovered after March 31, 1974 and before September 1, 1992, it is considered "new oil". The Alberta government introduced in 1992 a Third Tier Royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 1, 1992. The new oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 30%. The old oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 35%.

The royalty reserved to the Crown in respect of natural gas production, subject to various incentives, is between 15% and 30%, in the case of new natural gas, and between 15% and 35%, in the case of old natural gas, depending upon a prescribed or corporate average reference price. Natural gas produced from qualifying intervals in eligible gas wells spudded or deepened to a depth below 2,500 metres is also subject to a royalty exemption, the amount of which depends on the depth of the well.

Oil sands projects are subject to a specific regulation made effective July 1, 1997, and expiring June 30, 2009, which, among other things, determines the Crown's share of crude and processed oil sands products.

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provided various incentives for exploring and developing oil reserves in Alberta. However, the Alberta Government announced in August of 2006 that four royalty programs were to be amended, a new program was to be introduced and the Alberta Royalty Tax Credit Program ("**ARTC**") was to be eliminated, effective January 1, 2007. The programs affected by this announcement are: (i) Deep Gas Royalty Holiday; (ii) Low Productivity Well Royalty Reduction; (iii) Reactivated Well Royalty Exemption; and (iv) Horizontal Re-Entry Royalty Reduction. The program being introduced is the Innovative Energy Technologies Program (the "**IETP**") which is intended to promote the producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP provides royalty reductions which are presumed to reduce financial risk. Alberta Energy will be the one to decide which projects qualify and the level of support that will be provided. The deadline for the IETP's third round of applications was May 31, 2007. The successful applicants have not yet been announced and it appears, based on the previous two rounds, that the selection process can take at least 8 months. The technical information gathered from this program is to be made public once a two-year confidentiality period expires.

On October 25, 2007, the Alberta government released a report entitled "The New Royalty Framework" containing the government's proposals for Alberta's new royalty regime that is scheduled to be effective on January 1, 2009. The proposed NRF includes new royalty formulas for conventional oil and natural gas that will operate on sliding scales that are determined by commodity prices and well productivity; in addition to the policy of "shallow rights reversion". The Alberta government is intending to implement this policy in order to maximize the development of currently undeveloped resources which is consistent with the government's objective of maximizing recovery of known gas resources, while increasing royalty revenues. The policy's objective is for the mineral rights to shallow gas geological formations that are not being developed to revert back to the government and be made available for resale. It appears that leaseholders will get a grace period before the shallower zones are reverted to the Crown, which is still to be determined. Substantial legislative, regulatory and systems updates will be introduced before changes become fully effective in January 2009. See "*Risk Factors – New Alberta Royalty Regime*".

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms from two years, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

Environmental legislation in the Province of Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta) (the "**EPEA**"), which came into force on September 1, 1993, and the *Oil and Gas Conservation Act* (Alberta) (the "**OGCA**"). The EPEA and OGCA impose stricter environmental standards, require more stringent compliance, reporting and monitoring obligations, and significantly increased penalties. In 2006, the Alberta Government enacted regulations pursuant to the EPEA to specifically target sulphur oxide and nitrous oxide emissions from industrial operations including the oil and gas industry. In addition, the reduction emission guidelines outlined in the *Climate Change and Emissions Management Amendment Act* came into effect on July 1, 2007. Under this legislation, Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12%. Industries have three options to choose from in order to meet the reduction requirements outlined in this legislation, and these are: (i) by making improvement to operations that result in reductions; (ii) by purchasing emission credits from other sectors or facilities that have emissions below the 100,000 tonne threshold and are voluntarily reducing their emission; or (iii) by contributing to the Climate Change and Emissions Management Fund. Industries can either choose one of these options or a combination thereof. The Company will be committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and an expense nature as a result of the increasingly stringent laws relating to the protection of the environment, and will be taking such steps as required to ensure compliance with the EPEA and similar legislation in other jurisdictions in which it operates. The Company believes that it is in material compliance with applicable environmental laws and regulations. The Company also believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

In January 24, 2008, the Alberta Government announced a new climate change action plan that will cut Alberta's projected 400 million tonnes of emissions in half by 2050. This plan is based on three areas: (i) carbon capture and storage, which will be mandatory for *in situ* oil sand facilities that use heavy fuels for steam generation; (ii) energy conservation and efficiency; and (iii) greening production through increased investment in clean energy technology, including supporting research on new oil sands extraction processes, as well as the funding of projects that reduce the cost of separating CO_2 from other emissions supporting carbon capture and storage.

In December, 2002, the Government of Canada ratified the Kyoto Protocol ("**Protocol**"). The Protocol calls for Canada to reduce its greenhouse gas emissions to 6% below 1990 "business-as-usual" levels between 2008 and 2012. Given revised estimates of Canada's normal emissions levels, this target translates into an approximately 40% gross reduction in Canada's current emissions. It is questionable, based on the Updated Action Plan announced by the federal government (see below), that the Kyoto target of 6% below 1990 emission levels will be enforced in Canada. Bill C-288, which is intended to ensure that Canada meets its global climate change obligations under the Kyoto Protocol, was passed by the House of Commons on February 14, 2007. On April 26, 2007, the Federal Government released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "**Action Plan**") also known as ecoACTION which includes the regulatory framework for air emissions. This Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy using products.

The Government of Canada and the Province of Alberta released on January 31, 2008 the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force, which recommends among others: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii) allocating new funding into projects through competitive process; and targeting research to lower the cost of technology.

In order to strengthen the Action Plan, on March 10, 2008, the Government of Canada released "Turning the Corner – Taking Action to Fight Climate Change" (the "**Updated Action Plan**") which provides some additional guidance with respect to the Government's plan to reduce greenhouse gas emissions by 20% by 2020 and by 60% to 70% by 2050.

The Updated Action Plan is primarily directed towards industrial emissions from certain specified industries including the oil sands, oil and gas and refining. The Updated Action Plan is intended to create a carbon emissions trading market, including an offset system, to provide incentive to reduce greenhouse gas emission and establish a market price for carbon. There are mandatory reductions of 18% from the 2006 baseline starting in 2010 and an additional 2% in subsequent years for existing facilities. This target will be applied to regulated sectors on a facility-specific, sector-wide or corporate basis; in the case of oils sands production, petroleum refining, natural gas pipelines and upstream oil and gas the target will be considered facility-specific (sectors in which the facilities are complex and diverse, or where emissions are affected by factors beyond the control of the facility operator). Emissions from new facilities, which are those built between 2004 and 2011, will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time, and will be granted a 3-year grace period during which no emissions intensity targets will apply. Targets will begin to apply on the fourth year of commercial operation and the baseline will be the third year's emissions intensity, with a 2% continuous annual emission intensity improvement required. The definition of new facility also includes greenfield facilities, major expansions constituting more than a 25% increase in a facility's physical capacity, as well as transformations to a facility that involve significant changes to its processes. For upstream oil and gas and natural gas pipelines, it will be applied using a sector-specific approach. For the oil sands, its application will be process-specific, oil sands plants built in 2012 and later, those which use heavier hydrocarbons, up-graders and *in-situ* production will have mandatory standards in 2018 that will be based on carbon capture and storage.

In the following regulated sectors, the Updated Action Plan will apply only to facilities exceeding a minimum annual emissions threshold: (i) 50,000 tonnes of CO_2 equivalent per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 equivalent per upstream oil and gas facilities; and (iii) 10,000 Boe/d/company. These proposed thresholds are significantly stricter than the current Alberta regulatory threshold of 100,000 tonnes of CO_2 equivalent per year per facility.

Four separate compliance mechanisms are provided in respect of the above targets: Technology Fund contributions, offset credits, clean development credits and credits for early action. The most significant of these compliance mechanisms, at least initially, will be the Technology Fund and for which regulated entities will be able to contribute in order to comply with emissions intensity reductions. The contribution rate will increase over time, beginning at $15 per tonne for the 2010-12 period, rising to $20 per tonne in 2013, and thereafter increasing at the nominal rate of GDP growth. Contribution limits will correspondingly decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce greenhouse gas emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as mentioned above.

The offset system is intended to encourage emissions reductions from activities outside of the regulated sphere, allowing non-regulated entities to participate in and benefit from emissions reduction activities. In order to generate offset credits, project proponents must propose and receive approval for emissions reduction activities that will be verified before offset credits will be issued to the project proponent. Those credits can then be sold to regulated entities for use in compliance or non-regulated purchasers that wish to either cancel the offset credits or bank them for future use or sale.

Under the Updated Action Plan, regulated entities will also be able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol. The purchase of such Emissions Reduction Credits will be restricted to 10% of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations.

Finally, a one-time credit of up to 15 Mt worth of emissions credits will be awarded to regulated entities for emissions reduction activities undertaken between 1992 and 2006. These credits will be both tradable and bankable.

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not currently possible to predict either the nature of those requirements or the impact on the Company and its operations and financial condition at this time.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors and senior officers of the Company, any shareholder who beneficially owns more than 10% of the outstanding Common Shares, or any known associate or affiliate of such persons, in any transactions since the beginning of the Company's last completed financial year or in any proposed transaction which has materially affected or will materially affect the Company except as described herein.

MATERIAL CONTRACTS

Except for contracts entered into by the Company in the ordinary course of business or otherwise disclosed herein, the Company has no contracts which can reasonably be regarded as material.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Company during, or related to, the Company's most recently completed financial year other than GLJ, the Company's independent engineering evaluators and KPMG LLP, the Company's auditors.

To the knowledge of the Company, GLJ, or principals thereof, did not have any registered or beneficial interests, direct or indirect, in any securities or other property of the Company or of the Company's associates or affiliates either at the time they prepared the statement, report or valuation prepared by them, at any time thereafter or to be received by them.

KPMG LLP has advised the Company that they are independent within the meaning of the Rules of Professional Conduct as outlined by the Institute of Chartered Accountants of Alberta and its partners did not hold any registered or beneficial ownership interests, directly or indirectly, in the securities of the Company or its associates or affiliates.

ADDITIONAL INFORMATION

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, is contained in the Company's Information Circular for the most recent annual meeting of shareholders that involved the election of directors. Additional financial information is provided in the Company's financial statements and management's discussion and analysis for the most recently completed financial year. Documents affecting the rights of security holders, along with other information relating to the Company, may be found on SEDAR at www.sedar.com.

SCHEDULE A

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

To the board of directors of Madalena Ventures Inc. (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 6, 2008	Canada	-	$2,752	-	**$2,752**

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 12, 2008

Bryan M. Joa, P. Eng.
Vice-President

SCHEDULE "B"

FORM 51-101 F3
REPORT OF MANAGEMENT AND DIRECTORS
ON RESERVES DATA AND OTHER INFORMATION

Management of Madalena Ventures Inc. (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 December 31, 2007, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator will be filed with the securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of the Company has:

- reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;
- met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and
- reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of 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 on the recommendation of the Reserves Committee approved:

- the content and filing with securities regulatory authorities of Form 51-101F1 containing the reserves data and other oil and gas information;
- the filing of Form 51-102F2 which is the report of the independent qualified reserves evaluator on the reserves data; and
- 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, our variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Dated at Calgary, Alberta, this 22nd day of April, 2008

(signed) "*Ken Broadhurst*"	(signed) "*Ving Y. Woo*"
Ken Broadhurst, President & Chief Executive Officer and Director	Ving Y. Woo, Director and Chairman of the Reserves Committee
(signed) "*Dwayne Warkentin*"	(signed) "*Raymond G. Smith*"
Dwayne Warkentin, Senior Vice-President & Chief Operating Officer	Raymond G. Smith, Director and Chairman of the Board of Directors