Madalena Ventures Inc.

NOTICE TO READERS

Amended Annual Information Form

For the year ended December 31, 2012

Following is an amended Annual Information Form (the "Amended AIF") of Madalena Ventures Inc. for the year ended December 31, 2012. The Amended AIF corrects certain minor errors in information contained in the copy of the Annual Information Form that was previously filed with applicable securities regulatory authorities in Canada on April 30, 2012 (the "Original AIF"), which is available electronically at www.sedar.com. **None of the changes are material.** For ease of reference, following is a brief description of each correction.

Reference	**Correction**
Page 16; "*Summary of Oil and Gas Reserves and Net Present Values of Future Net Revenue at December 31, 2012*"	There was an addition error in the Original AIF for CANADA in the Total Proved Plus Probable, Gross Natural Gas Reserves. The Amended AIF corrects this.
Page 16 and 17; "*Summary of Oil and Gas Reserves and Net Present Values of Future Net Revenue at December 31, 2012*"	The Original AIF disclosed that that the units for $/BOE Unit Value Before Tax Discounted at 10% is $MM. The Amended AIF corrects this by removing the MM notation. The correct unit is $/BOE.
Page 18; "*Total Future Net Revenue (Undiscounted) at December 31, 2012*"	The Original AIF disclosed that the Future Net Revenue Before Income Tax of $31.912 MM CDN and the Future Net Revenue After Income Tax of $31.401 MM CDN. The Amended AIF corrects these numbers to Future Net Revenue Before Income Tax of $31.909 MM CDN and the Future Net Revenue After Income Tax of $31.398 MM CDN.
Page 18; "*Future Net Revenue by Production Group at December 31, 2012*"	The Original AIF disclosed that the Unit Value Before Income Tax Discounted at 10% expressed in $/boe for Argentina - Total Proved was 5.437 and for Total Proved plus Probable was 10.887. The Amended AIF corrects this to the Unit Value Before Income Tax Discounted at 10% expressed in $/boe for Argentina - Total Proved of 13.88 and for Total Proved plus Probable of 16.85.

Page 18; "*Future Net Revenue by Production Group at December 31, 2012*"	The Original AIF disclosed that that the Unit Value Before Income Tax Discounted at 10% expressed in $/boe for Canada - Total Proved was 29.42 and for Total Proved plus Probable was 29.16. The Amended AIF correct this is to the Unit Value Before Income Tax Discounted at 10% expressed in $/boe for Canada - Total Proved was 8.40 and for Total Proved plus Probable was 8.94.
Page 19; "*Future Net Revenue by Production Group at December 31, 2012*"	The Original AIF disclosed that the Unit Value Before Income Tax Discounted at 10% expressed in $/boe for Total Company, Total Proved was 27.93 and for Total Proved plus Probable was 29.65. The Amended AIF corrects this to the Unit Value Before Income Tax Discounted at 10% expressed in $/boe for Total Company, Total Proved is 9.46 and for Total Proved plus Probable is 10.52.

Page 19; "*Future Net Revenue by Production Group at December 31, 2012*"	The Original AIF disclosed that the Future Net Revenue Before Income Tax Discounted at 10% for the Total Company, Proved Reserves, Light and Medium Crude Oil was $12.038 MM CDN. The Amended AIF corrects this number to Future Net Revenue Before Income Tax Discounted at 10% for the Total Company, Proved Reserves, Light and Medium Crude Oil of $12.380 MM CDN.
Page 19; "*Future Net Revenue by Production Group at December 31, 2012*"	The Original AIF disclosed that the Future Net Revenue Before Income Tax Discounted at 10% for the Total Company, Total Proved was $18.581 MM CDN. The Amended AIF corrects this number to Future Net Revenue Before Income Tax Discounted at 10% for the Total Company, Proved Reserves of $18.923 MM CDN.
Page 25; "*Undeveloped Reserve - TOTAL Company, Probable Undeveloped Reserves* "	The Original AIF disclosed the Table for TOTAL company as that of CANADA only. The ARGENTINA numbers were not included. The Amended AIF corrects this by adding the Canadian and Argentine numbers for the Probable Undeveloped Reserves.

Page 30; "*Production Estimates* "	The Original AIF discloses the Total Probable Argentina Natural Gas production estimate as 85 Mcf/d and 44 Boe/d. The Amended AIF corrects this Total Probable production estimate to 25 Mcf/d and 34 Boe/d

DATED: May 2, 2013

Madalena Ventures Inc.

Annual Information Form

(AMENDED)

See accompanying Notice to Readers dated May 2, 2013 for a description of changes from the original Annual Information Form filed on April 30, 2013.

Year Ended December 31, 2012

Effective May 2, 2013

(re-filed on May 2, 2013 for certain immaterial corrections)

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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
Mstb	1,000 stock tank barrels	MMbtu	million British Thermal Units
bopd	barrels of oil per day	Bcf	billion cubic feet
NGLs	natural gas liquids	Tcf	trillion cubic feet
STB	stock tank barrels	Gj	gigajoule

Other

AECO	EnCana Corp.'s natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
ºAPI	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
m^3	cubic metres
MBOE	1,000 barrels of oil equivalent
Mstboe	1,000 stock tank barrels of oil equivalent
$000's or M$	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

All calculations converting natural gas to barrels of oil equivalent ("**boe**") have been made using a conversion ratio of six thousand cubic feet (6 Mcf) of natural gas to one barrel of oil (1 bbl), unless otherwise stated. The use of boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf of natural gas to one bbl of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain of the statements contained herein including, without limitation, financial and business prospects and financial outlook, reserve and production estimates, expected levels of activity, budgeted capital expenditures and the method of funding thereof, drilling, completion and tie-in plans, industry conditions in Argentina and productive capacity of wells may be forward-looking statements. Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and similar expressions may be used to identify these forward-looking statements. These statements reflect management's current beliefs and are based on information currently available to management. In addition, statements relating to "reserves" are deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future.

Forward-looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements including, but not limited to, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates and estimated production rates, changes in royalty rates and expenses, environmental risks, partner risk and competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, changes in the regulatory and taxation environment, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources and the risk factors outlined under "Risk Factors" and elsewhere herein. The recovery and reserve estimates of Madalena's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

Forward-looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although Madalena believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because Madalena can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which Madalena operates; the timely receipt of any required regulatory approvals; the ability of Madalena to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of Madalena to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development of exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of Madalena to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which Madalena operates; and the ability of Madalena to successfully market its oil and natural gas products.

Readers are cautioned that the foregoing list of factors is not exhaustive, Additional information on these and other factors that could affect Madalena's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the System for Electronic Document Analysis and Retrieval ("**SEDAR**") website (www.sedar.com) and Madalena's website (www.madalena-ventures.com). Although the forward-looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward-looking statements. Investors should not place undue reliance on forward-looking statements. These forward-looking statements are made as of the date hereof and the Corporation assumes no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

Forward-looking statements and other information contained herein concerning the oil and gas industry and management's general expectations concerning this industry is based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which management believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Corporation is not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

NON-GAAP MEASURES

Funds flow from operations and operating netbacks are not recognized measures under GAAP. Management believes that funds flow from operations and operating netbacks are useful supplemental measures as they demonstrate Madalena's ability to generate the cash necessary to repay debt or fund future growth through capital investment. Readers are cautioned, however, that these measures should not be construed as an alternative to net income determined in accordance with GAAP as an indication of Madalena's performance. Madalena's method of calculating these measures may differ from other companies and accordingly they may not be comparable to measures used by other companies. For these purposes, Madalena defines funds flow from operations as cash provided by operations before changes in non-cash operating working capital and defines operating netbacks as revenue less royalties and operating expenses.

ANALOGOUS INFORMATION

Certain information in this document may constitute "analogous information" as defined in National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities, including, but not limited to, information relating to the areas in geographical proximity to prospective exploratory lands held or to be to be held by Madalena. Management of Madalena believes the information is relevant as it helps to define the lands characteristics in which Madalena may hold an interest. Madalena is unable to confirm that the analogous information was prepared by a qualified reserves evaluator or auditor. Such information is not an estimate of the reserves or resources attributable to lands held or to be held by Madalena and there is no certainty that the reserves data and economics information for the lands held or to be held by Madalena will be similar to the information presented herein. The reader is cautioned that the data relied upon by Madalena may be in error and/or may not be analogous to such lands to be held by Madalena.

CERTAIN DEFINITIONS

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

"**2001 Arrangement**" means the amalgamation of Madalena Gold Company and Corsair Minerals Inc., as part of a statutory arrangement (under the former *Company Act* (British Columbia) involving Pacific Genesis Technologies, Madalena Gold Company, and Corsair Minerals Inc., which closed on September 14, 2001;

"**2006 Arrangement**" means the plan of arrangement whereby the mineral exploration assets and marketable securities related to the mineral exploration assets of the Corporation were transferred to Great Bear, which was formerly a wholly-owned subsidiary of Madalena, with each Shareholder receiving one common share of Great Bear for every fifteen (15) Common Shares held;

"**ABCA**" means the Alberta *Business Corporations Act;*

"**AIF**" means this annual information form of the Corporation dated April 26, 2013;

"**Apache**" means Apache Energia Argentina S.R.L.;

"**Apco**" means Apco Oil and Gas International Inc.;

"**Board**" or "**Board of Directors**" means the board of directors of the Corporation;

"**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;

"**Coiron Amargo Block**" means the Coiron Amargo exploration block in the province of Neuquén, Argentina, which Madalena holds through Madalena Argentina;

"**Common Shares**" means the common shares in the capital of Madalena;

"**Corporation**" or "**Madalena**" means Madalena Ventures Inc., a corporation existing under the laws of the Province of Alberta;

"**Cortadera Block**" means the Cortadera exploration block in the province of Neuquén, Argentina which Madalena holds through Madalena Argentina;

"**Curamhuele Block**" means the Curamhuele exploration block in the province of Neuquén, Argentina which Madalena holds through Madalena Argentina;

"**Great Bear**" means Great Bear Resources Inc.;

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

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

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

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

"**GyP**" means Gas y Petroleo del Neuquén S.A., the provincial hydrocarbon company of the Province of Neuquén;

"**HIDENESA**" means Hidrocarburos del Neuquén Sociedad Anonime, the predecessor of GyP as the provincial hydrocarbon company of the Province of Neuquén;

"**MASA**" means Madalena Austral S.A., an entity existing pursuant to the laws of Argentina and a subsidiary of the Corporation;

"**McDaniel**" means McDaniel and Associates Consultants Ltd.;

"**McDaniel Report**" means the report of McDaniel dated April 26 evaluating the Canadian crude oil, natural gas liquids and natural gas reserves of the Corporation as at December 31, 2012.;

"**MVIHC**" means Madalena Ventures International Holding Company Inc., an entity existing pursuant to the laws of Barbados and a wholly-owned subsidiary of the Corporation;

"**MVII**" means Madalena Ventures International Inc., an entity existing pursuant to the laws of Barbados and a wholly-owned subsidiary of MVIHC;

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

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

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

(f) in relation to the Corporation's interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation;

"**NGL**" means 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*;

"**Online**" means Online Energy Inc., a corporation existing pursuant to the laws of the Province of Alberta;

"**Ryder Scott**" means Ryder Scott Petroleum Consultants;

"**Ryder Scott Report**" means the report of Ryder Scott dated April 26, 2013 evaluating the Argentinean crude oil, natural gas liquids and natural gas reserves of the Corporation as at December 31, 2012;

"**Shareholders**" means holders of Common Shares;

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

"**US dollars**" or "**US $**" means U.S. dollars.

Unless stated otherwise, references to "dollars" or "$" reflect Canadian currency.

CORPORATE STRUCTURE

General

Madalena was created under the laws of the Province of British Columbia on September 14, 2001 pursuant to the Arrangement.

On September 30, 2004 Madalena Ventures Inc. amalgamated with its wholly-owned subsidiary, RMS Medical Systems Research (B.C.) Ltd.

On August 22, 2006 the Corporation completed the 2006 Arrangement.

On September 26, 2006, the Corporation was continued from the Province of British Columbia to the Province of Alberta.

On April 1, 2013, Madalena amalgamated with its wholly-owned subsidiary, Online.

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

The Corporation's principal office is located at 200, 441 - 5th Avenue S.W., Calgary, Alberta, T2P 2V1, and the Corporation's registered office is located at Suite 2400, 525 - 8th Avenue S.W., Calgary, Alberta, T2P 1G1.

Inter-corporate Relationships

MVIHC was incorporated on December 14, 2007 under the *Companies Act* of Barbados. MVIHC does not own any operating oil and gas assets and was incorporated for the sole purpose of incorporating a subsidiary under the laws of Barbados, being MVII. MVIHC also facilitates future capitalization of its subsidiary, MVII.

MVII was incorporated on December 14, 2007 under the *Companies Act of Barbados* for the purposes of carrying on oil and natural gas exploration and development activities in Tunisia and other countries.

MASA was incorporated in the Province of Rio Negro on December 17, 2008 under the national Company Act (Law number 19.550) for the purpose of oil and natural gas exploration and development activities in Argentina.

The Corporation owns 100% of the outstanding common shares of MVIHC which in turn owns 100% of the outstanding common shares of MVII. Prior to the sale of the Corporation's Tunisian assets on February 1, 2010, all of the Corporation's activities in Tunisia were conducted through MVII. Madalena owns 90% and MVII owns 10% of the outstanding shares of MASA, respectively. Madalena carries on all of its exploration and development activities in Argentina through MASA.

GENERAL DEVELOPMENT OF THE BUSINESS

Madalena is an independent, Canadian-based, domestic and international upstream oil and gas company, with its principal business activities being exploration, development and production of crude oil, natural gas liquids and natural gas. The Corporation, through MASA, has exploration and production operations in Argentina. In late 2012, the Corporation acquired Online and established exploration and production operations in Canada. The following is a summary of the business operations of the Corporation and its subsidiaries over the last three completed financial years.

Three Year History

2010

Corporate Matters

On November 10, 2010, the Corporation completed a bought deal financing by way of short form prospectus, issuing 40,775,000 Common Shares at an issue price of $0.65 per Common Share, resulting in aggregate gross proceeds of approximately $26,503,750.

Neuquén Basin - Argentinean Operations

Coiron Amargo Block

In February 2010, the Corporation announced it had finalized formal documentation with Apco and had received all required approvals to enter into the two-stage, multi-well drilling program with Apco to drill a minimum of two exploration wells on the farmout lands to earn 25% (net 17.5%) of Madalena's current 70% net working interest in the farmout (excluding the Norte 2 structure in which the CAN X-2 well was drilled) with the option to drill two additional earning wells to earn an additional 25% (net 17.5%) of Madalena's 70% net working interest in the Coiron Amargo Block.Such farmout has a provisdion such that should cumulative investments under the farmout exceeded US$18.4 million (including VAT), Apco would automatically earn 50% (net 35%) of Madalena's 70% net working interest in the Coiron Amargo Block and each working interest owner would be responsible for subsequent costs based on their participating interest.

In May 2010, the Corporation successfully completed negotiations for the extension of the term of the exploration period on the Coiron Amargo Block totalling three years commencing from the end of the initial three year exploration period on November 9, 2010. The first extension period was a one year continuation to the existing exploration period to be followed by a new two year exploration period. There was no requirement to relinquish non-commercial or non-prospective acreage on the Coiron Amargo Block until the end of the one year continuation. The subsequent new two year exploration period for the Coiron Amargo Block required additional gross work commitments equal to $US 3.1 million which includes the drilling of at least one well on the Coiron Amargo Block.

In August 2010, Madalena drilled and cased the CAN X-3 exploratory well as a potential oil discovery. The CAN X-3 exploration well encountered two zones with hydrocarbon potential, being the Sierras Blancas formation and the Vaca Muerta shale formation. In October 2010, the bottom 23 feet in the Sierras Blancas formation was perforated and the interval was tested.

In November 2010 Madalena drilled the CAN X-1 exploration well, encountering several zones with hydrocarbon potential. During testing, two intervals were perforated in the Sierras Blancas formation and the well was tested. The Corporation completed testing operations and placed the well on production.

Curamhuele Block

In May 2010, the Corporation successfully completed negotiations for the extension of the term of the exploration period on the Curamhuele Block totalling three years commencing from the end of the initial three year exploration period on November 9, 2010. The first extension period was a one year continuation to the existing exploration period to be followed by a new two year exploration period. There was no requirement to relinquish non-commercial or non-prospective acreage on the Curamhuele Block until the end of the one year continuation. The subsequent new two year exploration period for the

Curamhuele Block required gross additional work commitments in the amount of $US 2.0 million, which included the drilling of at least one well on the Curamhuele Block.

Between October 2010 and April 2011, Madalena drilled the Curamhuele X-1001 exploratory well to a total depth of 8,430 feet without encountering commercial quantities of hydrocarbons. The well was abandoned.

Cortadera Block

In May 2010, the Corporation successfully completed negotiations for the extension of the term of the exploration period on the Cortadera Block. The Corporation received a second three year exploration period commencing on October 26, 2010. The first extension period is a one year continuation to the existing exploration period to be followed by a new two year exploration period. There was no requirement to relinquish non-commercial or non-prospective acreage on the Cortadera Block until the end of the one year continuation. The new three year exploration period required an additional gross work commitment in the amount of $US6.0 million which may be fulfilled through conducting additional seismic or the drilling of a well.

In October 2010, the Corporation announced, subject to final government approval, a farmout of the Cortadera Block to Apache. The terms of the farmout provided for Apache to carry Madalena's exploration commitments on the Cortadera Block including the drilling of at least one exploration well to earn a 50% working interest in the Cortadera Block. When the farmout was completed, Madalena would retain a 40% working interest in the Cortadera Block.

Tunisian Operations

Effective February 1, 2010, the Corporation sold its interest in the Remada Sud Permit in Tunisia to Storm Ventures International Inc. for cash consideration of USD $4 million.

2011

Argentinean Operations

Coiron Amargo Block

In March 2011, the Corporation drilled and cased the CAS X-1 exploration well in the southern portion of the block and in May 2011 drilled the CAN X-4 well approximately 16 km away in the northern portion of the block. Oil and gas shows were evident in both wells during the drilling of the Sierras Blancas formation and the non-conventional Vaca Muerta formation.

In June and July 2011, the Corporation tested the CAS X-1 and CAN X-4 wells, respectively, in the Sierras Blancas formation and placed them on production. Both the CAS X-1 and CAN X-4 wells were drilled at no cost to the Corporation as part of an earlier farm-out agreement. Following the completion and initial testing of the wells, under the earning provisions of the farm-out agreement, Madalena's working interest in the block decreased at the end of July 2011 from 52.5% to 35%.

In December 2011, Madalena commenced a three stage hydraulic fracture stimulation of the Vaca Muerta formation on the CAS X-1 well location and commenced drilling the CAS X-4 exploration well located approximately nine kilometres south east of the CAS X-1 discovery well. In the northern portion of the Coiron Amargo Block, installation of a central facility and gas pipeline was also underway which, when completed, would remove restrictions to flow rates from four producing Sierras Blancas wells in the area.

Curamhuele Block

In February 2011, Madalena recommenced drilling of the Curamhuele X-1001 exploration well and began site preparation work to drill the Yapai X-1001 thrust play well situated 5 km to the south west of Curamhuele X¬1001.

In April 2011, the Curamhuele X-1001 well as abandoned.

In June 2011, Madalena completed drilling the Yapai X-1001 well, penetrating the Lower Troncoso, Avile and Agrio formations. The Avile and Agrio formations were perforated and swab tested in three stages and light gravity crude oil was recovered from each test as well as natural gas without any measurable formation water indicating a trapped hydrocarbon system. A fracture stimulation program may be further assessed and executed at some point in the future to test and evaluate these formations. The well may also be re-entered at a later date and deepened to the Mulichinco and Vaca Muerta shale formation.

Cortadera Block

In April 2011, Madalena received formal government approval of the previously announced farmout of the Cortadera Block to Apache. The Corporation also received approval of its application to convert the three year extension of the license into a one year continuation of the first exploration period to be followed by a new two year exploration period.

In September 2011, the CorS X-1 exploration well was drilled with joint venture partner and operator Apache to a total depth of 14,760 feet. Based on electric logs in conjunction with select full diameter and side wall cores, the well encountered a gross thickness of 1,706 feet in the Vaca Muerta shale formation, 1,893 feet in the Quintuco formation overlying the Vaca Muerta formation and 676 feet in the Mulichinco formation. Additional rotary sidewall cores were obtained for analysis in the Agrio formation overlying the Mulichinco formation.

2012

Corporate Matters

On March 7, 2012, the Corporation completed a bought deal financing by way of short form prospectus issuing 54,000,000 Common Shares at an issue price of $1.25 per Common Share, resulting in aggregate gross proceeds of $67,500,000.

On April 24, 2012, the Corporation adopted a shareholder rights plan (the "**Rights Plan**") for which Shareholder approval was received at the Corporation's annual and special meeting of Shareholders held on June 14, 2012. The Rights Plan is designed to provide Shareholders and the Board with adequate time to consider and evaluate any unsolicited bid made for the Corporation, to provide the Board with adequate time to identify, develop and negotiate value-enhancing alternatives, if considered appropriate, to any such unsolicited bid, to encourage the fair treatment of Shareholders in connection with any take-over bid for the Corporation and to ensure that any proposed transaction is in the best interests of the Shareholders.

On November 1, 2012 the Corporation acquired all of the common shares of Online for a total purchase price of approximately $16.1 million plus the assumption of debt in the amount of approximately $5.5 million.

On November 27, 2012, the Corporation announced the appointment of Mr. Kevin Shaw to the office of President and Chief Executive Officer of the Corporation and appointed Mr. Shaw as a director on the Board. Alongside Mr. Shaw was a newly announced full cycle operating team including the appointment of officers Mr. Steve Dabner (Vice President, Exploration), Brent Foster (Vice President, Engineering) and Rob Stanton (Vice President, Operations).

Argentinean Operations

Coiron Amargo Block

On Coiron Amargo Sur, in February 2012 the Company drilled and cased the CAS X-4 well approximately nine kilometers south east of the CAS X-1 discovery well drilled in 2011 and in March 2012 drilled and cased to TD the CAS X-2 vertical exploration well in the center of the block. At CAS X-4 a full diameter core was taken through most of the Vaca Muerta shale formation interval which will be used to optimize future wells in the Vaca Muerta formation.

In March 2012 an application by the Coiron Amargo joint venture to convert the northern 108 km^2 of the 404 km^2 block to a 25 year exploitation concession (Coiron Amargo Norte) was approved by the Province of Neuquén. In addition, the exploration period for the remainder of the block (Coiron Amargo Sur) was extended to November 8, 2013. Madalena's remaining share of future development commitments associated with Coiron Amargo Norte to December 31, 2013 is approximately $4.1 million plus VAT.

On Coiron Amargo Norte, in May 2012 the Company completed drilling the CAN 5 development well located within the CAN X-1 Sierras Blancas structure and in June 2012 the Company completed drilling the CAN 7 development well located within the CAN X-3 Sierras Blancas structure.

In December 2012, the CAN-8 development well located 800 meters south east of the existing CAN 7 oil producer on the northern portion of the block (i.e. Coiron Amargo Norte), was cased to a total depth ("TD") of 10,433 feet. Oil and gas were encountered in both the unconventional Vaca Muerta shale and the conventional Sierras Blancas zones of interest. The Vaca Muerta formation interval encountered by the well was approximately 340 feet (or 104 meters) thick and in the Sierras Blancas formation the well encountered an approximate gross hydrocarbon column of 98 feet (or 30 meters). Completion and testing in the Sierras Blancas formation is expected to commence in early 2013.

The extension of Coiron Amargo Sur to November 8, 2013 required additional work commitments of US$ 33.5 million (Madalena share – US$ 13.0 million of which approximately US$ 4.9 million plus VAT remains outstanding). The exploration block (Coiron Amargo Sur) qualifies for an additional one year extension period at the end of the exploration period in the fourth quarter of 2013.

Cortadera Block

In March 2012 Apache completed a two stage hydraulic fracture stimulation of the Vaca Muerta formation in the CorS X-1 vertical exploration well. Further work to assess the Vaca Muerta and/or uphole formations (i.e. Quintuco, Mulichinco, and Agrio zones) is required to fully evaluate this deep exploration test.

The initial exploration period for the Cortadera Block in the Province of Neuquén had an initial expiry of October 26, 2011. A new proposal was made by the joint venture to formalize an extension of the initial exploration period based on a proposed work plan for the block. As of December 31, 2012, the original proposal was yet to be finalized and discussions between the Province of Neuquen and the joint venture were recently reopened resulting in the decision to submit a new proposal. During the first quarter of 2013, the joint venture submitted a revised proposal and is currently working towards approval of an agreed upon work program for the block. As at December 31, 2012 the Company had incurred cumulative costs of approximately $2.4 million with respect to this block. A delay or rejection of the extension terms may result in an impairment of these costs.

Curamhuele Block

At the Cur X-1 well the Company mobilized a service rig in the second quarter of 2012 for its planned three stage fracture stimulation of the Lower Agrio shale formation which is oil saturated and an estimated 590 feet in thickness. After attempts to remove certain down-hole equipment in order to install casing for the fracture stimulation were unsuccessful operations were suspended at the Cur X-1 location with the potential to come back to this location at a later date to conduct further operations on the well.

In March 2012 the exploration period for the block was extended to November 8, 2013. The extension of the block required additional work commitments of US$ 17.6 million (Madalena share – US$ 17.6 million of which approximately US $13.7 million plus VAT remains outstanding). The exploration block qualifies for an additional one year extension after November 13, 2013. In December 2012, Madalena initiated the process to qualify the Curamhuele block for an additional one year extension. Throughout the first quarter of 2013, the Company has made steady progress with respect to this application and is currently in the advanced stages of the approval process.

Canadian Operations

In late 2012, the Corporation commenced operations on its Greater Paddle River area assets in Alberta, Canada. Prior to year-end, the Corporation drilled a 100% working interest well in Canada at Niton which was cased as a potential Notekewin gas well.

Recent Developments

Corporate – Management Changes and Appointments

On January 9, 2013, Mr. Dwayne Warkentin resigned from his positions of Vice Chairman of the Board and director and President of the Corporation.

On January 31, 2013, Mr. Anthony J. Potter resigned as a director of Madalena and effective February 28, 2013 resigned from his position of Vice President and Chief Financial Officer of the Corporation.

Effective February 28, 2013, Mr. Thomas Love was appointed Vice President, Finance and Chief Financial Officer of the Corporation.

DESCRIPTION OF THE BUSINESS AND OPERATIONS

Overview

Madalena is a Calgary, Alberta, Canada-based junior oil and gas exploration, development and production company with operations both internationally in the Neuquén Basin of Argentina and domestically within the Paddle River area of Alberta, Canada. Madalena's strategy is to create value through the generation of a portfolio of high quality oil and gas assets in proven hydrocarbon areas characterized by competitive fiscal terms and significant development potential and to deploy a balanced approach between lower risk development and high impact exploration.

Canadian Operations

The Corporation's domestic assets are comprised of exploration and development opportunities in the greater Paddle River area of central Alberta, Canada. These assets, which were acquired through the acquisition of Online on November 1, 2012, include 153 net sections of land (197 gross sections at 77.9% average working interest) across multiple light oil and liquids-rich gas resource plays. The acquisition of Online provides entry into the domestic exploration and production space with the opportunity to increase production and cash flow while continuing to develop and grow its international assets & business plan.

Madalena's current oil and gas operations located in the Paddle River area are subject to a set of risks that are different than its Argentinean assets. See "*Risk Factors*".

Argentinean Operations

The Corporation's international operations are comprised of exploration opportunities in the Neuquén Basin of Argentina, including significant exposure to unconventional shale resources. The portfolio consists of three highly prospective blocks, each comprised of a large land area on trend with known conventional discoveries and multiple shale or source rock formations, in each case, supported by extensive 2D and 3D seismic coverage and offsetting well data. The Neuquén Basin is a highly prolific oil and gas producing basin in Central Western Argentina that has extensive pipeline and facility infrastructure and a highly developed service industry. The Neuquén Basin remains relatively underexplored and has the potential for emerging unconventional resource plays.

As part of its corporate strategy, Madalena operates in the region through strategic alliances with local exploration and development companies.

A large portion of Madalena's current oil and gas operations are located in Argentina and therefore the Corporation is subject to foreign political and regulatory risk. See "*Risk Factors* ".

Competitive Conditions

There is considerable competition in both Canada and Argentina, respectively, for land positions and the drilling equipment and expertise necessary to explore for and develop those lands. There are also other, more established companies operating in both jurisdictions with access to broader technical skills, larger amounts of capital and other resources. This represents a significant risk for the Corporation, which must rely on limited resources and access to capital markets for funding of its activities. See "*Risk Factors*".

Contracts and Availability of Services

The Corporation engages the services of drilling rigs and related equipment for the completion of specific drilling operations. Once those operations are complete, the drilling rig and related equipment are released and the Corporation has no further contractual obligation to lease the equipment.

Canada

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment 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 Corporation and may delay exploration and development activities.

Argentina

There is a high utilization rate in Argentina for drilling rigs and other equipment. There has also been considerable interest in Argentina's shale oil and shale gas potential which in order to be explored and developed in a timely manner will require oil and gas service companies operating in the country to develop or procure additional specialized equipment and expertise.

Marketing and Future Commitments

Canada

Producers of oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. The price depends in part on oil type and quality, prices of competing fuels, distance to market, the value of refined products and the supply/demand balance. Oil exports may be made pursuant to export contracts with terms not exceeding one year in the case of light crude, and not exceeding two years in the case of heavy crude, provided that an order approving any such export has been obtained from 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 issue of such a licence requires the approval of the Governor in Council.

The price of natural gas sold in interprovincial and international trade 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 criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than two years or for a term of 2 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 issue of such a licence requires the approval of the Governor in Council.

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

Argentina

All oil production from the Coiron Amargo Block is currently sold on a spot basis to the domestic market. The price received for crude oil sales is calculated based on the Medanito light marker crude blend, less any quality adjustment and a discount on domestic oil sales. Produced crude oil is trucked to a treatment and storage facility where it is treated and stored until a sufficient sales volume has been reached. See *"Industry Conditions – Pricing and Marketing"*.

On acquisition of its Argentina exploration properties, Madalena and its joint venture partners agreed to work programs with the Province of Neuquén in Argentina. The Corporation has met its share of the amount to be spent to satisfy the total dollar value of the initial work programs and anticipates its current and proposed drilling programs will satisfy expenditure and work commitments associated with the extension of the blocks. See "*General Development of the Business – Recent Developments*".

Social or Environmental Policies

The Corporation's main environmental strategies include the preparation of comprehensive environmental impact assessments and assembling project-specific environmental management plans. The Corporation's practice is to do all that it reasonably can to ensure that it remains in material compliance with environmental protection legislation. The Corporation is committed to meeting its responsibilities to protect the environment wherever it operates and will take such steps as required to ensure compliance with environmental legislation. The Corporation also performs a detailed due diligence review as part of its acquisition process to determine whether the assets to be acquired are in regulatory and environmental compliance.

The Corporation expects to incur abandonment and site reclamation costs as existing oil and gas properties are abandoned and reclaimed. In 2012, expenditures for normal compliance with environmental regulations as well as expenditures beyond normal compliance were not material.

Management is responsible for reviewing the Corporation's Environment, Health and Safety ("**EH&S**") strategies and policies, including the Corporation's emergency response plan. Management reports to the Board of Directors as necessary and on an annual basis with respect to EH&S matters, including: (i) compliance with all applicable laws, regulations policies with respect to EH&S; (ii) on emerging trends, issues and regulations that are relevant to the Corporation; (iii) the findings of any significant report by regulatory agencies, external health, safety and environmental consultants or auditors concerning performance in EH&S; (iv) any necessary corrective measures taken to address issues and risks with regards to the Corporation's performance in the areas of EH&S that have been identified by management, external auditors or by regulatory agencies; (v) the results of any review with management, outside accountants, external consultants and/or legal advisors of the implications of major corporate undertakings such as the acquisition or expansion of facilities or ongoing drilling and testing operations, or decommissioning of facilities; and (vi) all incidents and near misses with respect to the Corporation's operations, including corrective actions taken as a result thereof.

Human Resources

The Corporation currently employs eight (8) full-time employees in Canada and three (3) full-time employees in Argentina. The Corporation also utilizes the services of several professionals on a part-time contract or consulting basis. The Corporation intends to add additional professional and administrative staff as the needs arise.

PRINCIPAL PROPERTIES

ARGENTINA

Neuquén Basin, Argentina

Among the petroleum producing regions of Argentina, the Neuquén Basin is the leading producer of hydrocarbons. According to current Instituto Argentino de Petroleo y del Gas ("**IAPG**") statistics, average daily production exceeds 250,000 bbls/d of oil and 2.4 bcf/day of gas. The Neuquén Basin was drilled initially in the 1920's and currently has over 177 fields, of which 129 are oil fields and 48 are natural gas fields.

The Neuquén Basin is a roughly triangular shaped foreland basin of approximately 137,000 square kilometres, located on the eastern front of the Andes Mountains in west-central Argentina. The basin stretches from the town of Malargue in the north over a distance of 650 kilometres to the south and has a maximum width of over 275 kilometres. The basin is situated entirely onshore and is part of the Sub Andean trend which extends the entire length of South America. Oil and natural gas are produced from multiple horizons ranging from Jurassic carbonates and sands to Cretaceous sands.

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

Coiron Amargo Block

The Coiron Amargo Block covers an area of approximately 100,000 acres and is situated approximately 650 miles southwest of Buenos Aires and approximately 75 miles east of the Cortadera Block.

In March 2012 an application by the Coiron Amargo joint venture to convert the northern 108 km^2 of the 404 km^2 block to a 25 year exploitation concession (Coiron Amargo Norte) was approved by the Province of Neuquén. Madalena's remaining share of future development commitments associated with Coiron Amargo Norte to December 31, 2013 is approximately $4.1 million plus VAT.

In addition, the exploration period for the remainder of the block (Coiron Amargo Sur) was extended to November 8, 2013.

The extension of Coiron Amargo Sur to November 8, 2013 required additional work commitments of US$ 33.5 million (Madalena share – US$ 13.0 million of which approximately US$ 4.9 million plus VAT remains outstanding). The exploration block qualifies for an additional one year extension after November 13, 2013.

Madalena and its partners in the Coiron Amargo Block are responsible for paying 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 Neuquén. GyP is responsible for its 10% share of the costs incurred in the development and production phase.

The Ryder Scott Report attributes proved reserves of 445.2 MBOE and proved plus probable reserves of 734.2 MBOE to Madalena's working interests in the Coiron Amargo Block. At December 31, 2012, the majority of structural anomalies identified on seismic over the Coiron Amargo Block have not been assigned proved or probable reserves. Further drilling on the Coiron Amargo Block is planned prior to submission of another commercial development plan seeking to convert additional acreage to a 25 year exploitation concession. No reserves have been assigned to the Cortadera Block or the Curamhuele Block given their early stage of development. 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 Argentinean blocks will lead to a commercial discovery or, if there is a discovery, that the Corporation will be able to realize such reserves. See "*Risk Factors*".

Cortadera Block

The Cortadera Block covers an area of approximately 124,000 acres and is situated along the western thrust belt of the Neuquén basin in the middle portion of the province of Neuquén, approximately 700 miles south and west of Buenos Aires. The first three year exploration term had a work commitment of $2.5 million US which included exploration costs, seismic and the drilling of at least one exploration well on the Cortadera Block. In 2010, the Corporation received an extension of the first exploration period to October 25, 2011 followed by a new two year exploration period. The extension required an additional gross work commitment the equivalent of US$6.0 million which could be fulfilled through conducting additional seismic or the drilling of a well.

In March 2011, Madalena received final government approval of a farm-out agreement for the Cortadera Block with Apache. The farm-out agreement provided for Apache to carry Madalena's exploration commitments on the Cortadera Block including the drilling of at least one exploration well to earn a 50% working interest in the Cortadera Block. In September 2011, Apache drilled the CorS X-1 earning well reducing Madalena's interest in the Cortadera Block from 90% to 40%.

Unless renegotiated, there is a requirement at the end of the first exploration period to relinquish 50% of the Cortadera Block.

The initial exploration period for the Cortadera Block in the Province of Neuquén had an initial expiry of October 26, 2011. A new proposal was made by the joint venture to formalize an extension of the initial exploration period based on a proposed work plan for the block. As of December 31, 2012, the original proposal was yet to be finalized and discussions between the Province of Neuquen and the joint venture were recently reopened resulting in the decision to submit a new proposal. During the first quarter of 2013, the joint venture submitted a revised proposal and is currently working towards approval of an agreed upon work program for the block. As at December 31, 2012 the Company had incurred cumulative costs of approximately $2.4 million with respect to this block. A delay or rejection of the extension terms may result in an impairment of these costs.

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Madalena and its partners in the Cortadera Block are responsible for paying 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 Neuquén. GyP is responsible for its 10% share of the costs incurred in the development and production phase. The Ryder Scott Report does not attribute any reserves to Madalena's working interest in the Cortadera Block.

Curamhuele Block

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 Neuquén, approximately 650 miles south and west of Buenos Aires and approximately 50 miles north of the Cortadera Block. In 2010, Madalena acquired its partners 20% interest in the Curamhuele Block and currently has a 90% interest in the Curamhuele Block. The first three year exploration term had a work commitment of US$3.0 million which included exploration costs, seismic and the drilling of at least one exploration well. In 2010, the Corporation received an extension of the first exploration period to November 8, 2011 followed by a new two year exploration period. The extension required an additional gross work commitment the equivalent of US$2.0 million which included the drilling of at least one well on the Curamhuele Block. In 2011 Madalena drilled the Curamhuele X-1001 and Yapai X-1001 wells fulfilling the Curamhuele Block's work commitments.

In March 2012 the exploration period for the block was extended to November 8, 2013. The extension of the block required additional work commitments of US$ 17.6 million (Madalena share – US$ 17.6 million of which approximately US $13.7 million plus VAT remains outstanding). The exploration block qualifies for an additional one year extension after November 13, 2013. In December 2012, Madalena initiated the process to qualify the Curamhuele block for an additional one year extension. Throughout the first quarter of 2013, the Company has made steady progress with respect to this application and is currently in the advanced stages of the approval process.

Madalena is responsible for paying 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 Neuquén. GyP is responsible for its 10% share of the costs incurred in the development and production phase. The Ryder Scott Report does not attribute any reserves to Madalena's working interest in the Curamhuele Block.

CANADA

Greater Paddle River Area

All of the Corporation's Canadian properties were acquired on November 1, 2012 pursuant to the acquisition of all of the issued and outstanding shares of Online. The principal properties are located in the greater Paddle River area of west-central Alberta. The greater Paddle River assets include 145 net sections of land (net 76.4% average working interest) across multiple light oil and liquids-rich gas resource plays. Online's resource plays are highlighted by the Ostracod light oil (43 of the 145 net sections) and Nordegg light oil and liquids-rich gas (131 of the 145 net sections) plays, and are complemented by the Rock Creek, Notikewan, Wilrich and Duvernay oil and liquids-rich gas plays.

The Corporation's reserve life index (RLI) is 9.3years based on Proved plus Probable reserves of approximately 3.2 MMBOE and total volume of production per day estimated by McDaniel for 2013 in the McDaniel Report. Average production for the two months ended December 31, 2012 from these properties was 629 boe/d, of which approximately 50% was oil and Ngls.

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

Disclosure of Reserves Data

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated April 26, 2013. The effective date of the statement is December 31, 2012 and the preparation date of the statement is April 26, 2013.The reserves data set forth below (the "**Reserves Data**") is based upon evaluations by each of Ryder Scott and McDaniel (collectively, the "**Reserve Engineers**")

The Ryder Scott Report and McDaniel Report are collectively referred to herein as the "**Reserve Reports**".

The Corporation engaged the Reserve Engineers to provide an evaluation of the Corporation's reserves as at December 31, 2012. The reserves data set forth below (the "**Reserves Data**") is based upon the Reserve Reports. The Reserve Reports have 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, 2012. The Reserves Data conforms with the requirements of NI 51-101. Madalena engaged Ryder Scott to provide evaluations of Proved Reserves and Proved plus Probable Reserves. Madalena engaged McDaniel to provide evaluations of Proved Reserves and Proved plus Probable Reserves. The Report on Reserves Data by our independent qualified reserves evaluators in Form 51-101F2 and the Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 are attached as Appendix "A" and Appendix "B", respectively

The Reserve Reports is based on certain factual data supplied by the Corporation and the Reserve Engineers' opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to the Corporation's petroleum properties and contracts (except for certain information residing in the public domain) were supplied by the Corporation to the Reserve Engineers and accepted without any further investigation. The Reserve Engineers accepted this data as presented and neither title searches nor field inspections were conducted. All statements relating to the activities of the Corporation for the year ended December 31, 2012 include a full year of operating data on the properties of the Corporation. As at December 31, 2012, all of the Corporation's reserves are located in Argentina and Canada.

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 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. See "*Special Note Regarding Forward-Looking Statements*".

Reserves Data (Forecast Prices and Costs)

The following tables provide a summary, by country and in the aggregate, of the Corporation's oil and gas reserves and net present value of future net revenue at December 31, 2012 using forecast prices and costs. All of the Corporation's properties are located in Argentina and Canada. Amounts shown are in US$ for the Argentina reserves and Canadian $ for the Canadian reserves. The Ryder Scott Report has been converted to Canadian $ based on the December 31, 2012 Bank of Canada noon spot exchange rate of 1 US $ = $0.9949 CDN for the Total reserves.

Summary of Oil and Gas Reserves and Net Present Values of Future Net Revenue at December 31, 2012

Forecast Prices and Costs

ARGENTINA — Reserves

	Light/Medium Crude Oil Gross (Mbbl)	Light/Medium Crude Oil Net (Mbbl)	Heavy Oil Gross (Mbbl)	Heavy Oil Net (Mbbl)	Natural Gas Gross (MMcf)	Natural Gas Net (MMcf)	Natural Gas Liquids Gross (Mbbl)	Natural Gas Liquids Net (Mbbl)	Oil Equivalent Gross (Mboe)	Oil Equivalent Net (Mboe)
Proved										
Developed Producing	226.3	199.1	-	-	185.2	163.0	-	-	257.2	226.3
Developed Non-Producing	28.0	24.6	-	-	7.1	6.3	-	-	29.2	25.6
Undeveloped	136.9	120.4	-	-	131.4	115.6	-	-	158.8	139.7
Total Proved	391.2	344.2	-	-	323.7	284.8	-	-	445.2	391.7
Probable	253.6	223.2	-	-	212.8	187.3	-	-	289.1	254.4
Total Proved Plus Probable	644.8	567.4	-	-	536.5	472.1	-	-	734.2	646.1

CANADA — Reserves

	Light/Medium Crude Oil Gross (Mbbl)	Light/Medium Crude Oil Net (Mbbl)	Heavy Oil Gross (Mbbl)	Heavy Oil Net (Mbbl)	Natural Gas Gross (MMcf)	Natural Gas Net (MMcf)	Natural Gas Liquids Gross (Mbbl)	Natural Gas Liquids Net (Mbbl)	Oil Equivalent Gross (Mboe)	Oil Equivalent Net (Mboe)
Proved										
Developed Producing	176.7	145.3	45.0	45.8	3792.6	3232.3	283.3	200.1	1137.0	929.9
Developed Non-Producing	-	-	-	-	1695.9	1522.8	42.4	29.9	325.0	283.7
Undeveloped	106.3	85.1	-	-	2049.7	1571.1	66.1	48.1	514.1	395.0
Total Proved	283.0	230.4	45.0	45.8	7538.1	6326.3	391.8	278.1	1976.1	1608.6
Probable	249.2	207.4	5.4	6.0	4477.1	3669.9	182.7	127.6	1183.6	952.7
Total Proved Plus Probable	532.3	437.7	50.4	51.9	12015.2	9996.1	574.6	405.7	3159.6	2561.3

TOTAL — Reserves

	Light/Medium Crude Oil Gross (Mbbl)	Light/Medium Crude Oil Net (Mbbl)	Heavy Oil Gross (Mbbl)	Heavy Oil Net (Mbbl)	Natural Gas Gross (MMcf)	Natural Gas Net (MMcf)	Natural Gas Liquids Gross (Mbbl)	Natural Gas Liquids Net (Mbbl)	Oil Equivalent Gross (Mboe)	Oil Equivalent Net (Mboe)
Proved										
Developed Producing	403.0	344.4	45.0	45.8	3977.8	3395.3	283.3	200.1	1394.2	1156.2
Developed Non-Producing	28.0	24.6	0.0	0.0	1703.0	1529.0	42.4	29.9	354.2	309.3
Undeveloped	243.2	205.5	0.0	0.0	2181.1	1686.7	66.1	48.1	672.9	534.7
Total Proved	674.2	574.6	45.0	45.8	7861.8	6611.1	391.8	278.1	2472.7	2000.3
Probable	502.8	430.6	5.4	6.0	4689.9	3857.2	182.7	127.6	1472.7	1207.1
Total Proved Plus Probable	1177.1	1005.1	50.4	51.9	12551.7	10468.2	574.6	405.7	3893.8	3207.4

ARGENTINA — Net Present Values of Future Net Revenue

Reserves Category US$	Before Income Taxes Discounted at (%/year) 0% MM	5% MM	10% MM	15% MM	20% MM	After Income Taxes Discounted at (%/year) [3] 0% MM	5% MM	10% MM	15% MM	20% MM	$/BOE Unit Value Before tax Discounted at 10%
Proved											
Developed Producing	5.534	5.165	4.814	4.491	4.198	5.278	4.935	4.607	4.304	4.029	21.27
Developed Non-Producing	0.360	0.317	0.275	0.237	0.203	0.324	0.285	0.246	0.211	0.179	10.73
Undeveloped	0.795	0.553	0.347	0.171	0.023	0.572	0.352	0.164	0.006	-0.127	2.48
Total Proved	6.689	6.036	5.437	4.900	4.424	6.175	5.572	5.018	4.520	4.080	13.88
Probable	9.127	6.998	5.450	4.309	3.454	7.308	5.385	4.016	3.030	2.310	21.42
Total Proved Plus Probable	15.816	13.034	10.887	9.209	7.878	13.483	10.957	9.033	7.550	6.390	16.85

CANADA	Net Present Values of Future Net Revenue										
Reserves Category	Before Income Taxes Discounted at (%/year)					After Income Taxes Discounted at (%/year) (3)					$/BOE Unit Value Before tax Discounted at
CDN$	0% MM	5% MM	10% MM	15% MM	20% MM	0% MM	5% MM	10% MM	15% MM	20% MM	10%
Proved											
Developed Producing	15.364	12.543	10.671	9.349	8.366	15.364	12.543	10.671	9.349	8.366	11.48
Developed Non-Producing	5.553	3.427	2.289	1.605	1.154	5.553	3.427	2.289	1.605	1.154	8.07
Undeveloped	4.340	1.999	0.554	-0.403	-1.071	4.340	1.999	0.554	-0.403	-1.071	1.40
Total Proved	25.257	17.969	13.514	10.551	8.450	25.257	17.969	13.514	10.551	8.450	8.40
Probable	22.744	14.077	9.379	6.559	4.728	17.257	11.003	7.508	5.344	3.898	9.84
Total Proved Plus Probable	48.001	32.045	22.893	17.111	13.178	42.514	28.972	21.022	15.896	12.348	8.94

TOTAL	Net Present Values of Future Net Revenue										
Reserves Category	Before Income Taxes Discounted at (%/year)					After Income Taxes Discounted at (%/year) (3)					$/BOE Unit Value Before tax Discounted at
CDN$	0% MM	5% MM	10% MM	15% MM	20% MM	0% MM	5% MM	10% MM	15% MM	20% MM	10%
Proved											
Developed Producing	20.870	17.682	15.460	13.817	12.543	20.615	17.453	15.255	13.631	12.374	13.37
Developed Non-Producing	5.911	3.742	2.563	1.841	1.356	5.875	3.711	2.534	1.815	1.332	8.29
Undeveloped	5.131	2.549	0.899	-0.233	-1.048	4.909	2.349	0.717	-0.397	-1.197	1.68
Total Proved	31.912	23.974	18.923	15.426	12.851	31.401	23.513	18.506	15.048	12.509	9.46
Probable	31.824	21.039	14.801	10.846	8.164	24.528	16.361	11.504	8.359	6.196	12.26
Total Proved Plus Probable	63.736	45.013	33.724	26.273	21.016	55.928	39.873	30.009	23.407	18.705	10.52

Total Future Net Revenue (Undiscounted) at December 31, 2012

Reserves Category	Revenue MM	Royalties MM	Operating Costs MM	Development Costs MM	Well Abandonment and Reclamation Costs MM	Future Net Revenue Before Income Taxes MM	Income Taxes MM	Future Net Revenue After Income Taxes (3) MM
Argentina – US$								
Total Proved Reserves	33.262	4.989	17.912	3.203	0.469	6.689	0.514	6.175
Total Proved Plus Probable Reserves	56.258	8.438	25.951	5.499	0.554	15.816	2.333	13.483

Reserves Category	Revenue MM	Royalties MM	Operating Costs MM	Development Costs MM	Well Abandonment and Reclamation Costs MM	Future Net Revenue Before Income Taxes MM	Income Taxes MM	Future Net Revenue After Income Taxes (3) MM
Canada – CDN$								
Total Proved Reserves	93.846	13.592	43.486	10.183	1.329	25.257	-	25.257
Total Proved Plus Probable Reserves	158.008	24.418	66.313	17.733	1.544	48.001	5.487	42.514

Reserves Category	Revenue MM	Royalties MM	Operating Costs MM	Development Costs MM	Well Abandonment and Reclamation Costs MM	Future Net Revenue Before Income Taxes MM	Income Taxes MM	Future Net Revenue After Income Taxes (3) MM
Total – CDN$								
Total Proved Reserves	126.938	18.556	61.307	13.370	1.796	31.909	0.511	31.398
Total Proved Plus Probable Reserves	213.979	32.813	92.132	23.204	2.095	63.736	7.808	55.928

Future Net Revenue by Production Group at December 31, 2012

Argentina US$	**Production Group**	**Future Net Revenue Before Income Taxes Discounted at 10% MM – US$**	**Unit Value Before Income Taxes Discounted at 10% $/boe**
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	5.437	13.88
	Heavy oil (including solution gas and other by-products)	-	-
	Natural gas (including by-products but excluding solution gas from oil wells)	-	-
	Total Proved	5.437	13.88
Proved plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	10.887	16.85
	Heavy oil (including solution gas and other by-products)	-	-
	Natural gas (including by-products but excluding solution gas from oil wells)	-	-
	Total Proved plus Probable	10.887	16.85

Canada CDN$	**Production Group**	**Future Net Revenue Before Income Taxes Discounted at 10% MM – CDN$**	**Unit Value Before Income Taxes Discounted at 10% $/boe**
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	6.971	16.88
	Heavy oil (including solution gas and other by-products)	0.364	7.14
	Natural gas (including by-products but excluding solution gas from oil wells)	6.179	5.40
	Total proved	13.514	8.40
Proved plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	12.457	15.68
	Heavy oil (including solution gas and other by-products)	0.426	7.63
	Natural gas (including by-products but excluding solution gas from oil wells)	10.009	5.85
	Total Proved plus Probable	22.892	8.94

Total CDN$	Production Group	Future Net Revenue Before Income Taxes Discounted at 10% MM – CDN$	Unit Value Before Income Taxes Discounted at 10% $/boe
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	12.380	15.39
	Heavy oil (including solution gas and other by-products)	0.364	7.14
	Natural gas (including by-products but excluding solution gas from oil wells)	6.179	5.40
	Total Proved	18.923	9.46
Proved plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	23.288	16.17
	Heavy oil (including solution gas and other by-products)	0.426	7.63
	Natural gas (including by-products but excluding solution gas from oil wells)	10.009	5.85
	Total Proved plus Probable	33.723	10.52

Notes to Reserves Data Tables:

(1) Columns may not add due to rounding.
(2) The crude oil, natural gas liquids and natural gas reserve estimates presented in the Reserve Reports are based on the definitions and guidelines contained in NI 51-101 and the COGE Handbook. A summary of those definitions are set forth below.
(3) The after tax amounts were determined using the Corporation's estimated tax pools as at December 31, 2012. The after tax net present value of the Corporation's oil and gas properties here reflects the tax burden on the properties on a stand-alone basis.

Reserve Categories

1. Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions, specifically the forecast prices and costs.

Reserves are classified according to the degree of certainty associated with the estimates.

(a) Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(b) Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

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

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

(ii) Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

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

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

2. Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserve estimates are prepared). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. in principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

Pricing Assumptions

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs.

Ryder Scott employed the following pricing, exchange rate and inflation rate assumptions as of December 31, 2012 in the Ryder Scott Report in estimating reserves data using forecast prices and costs.

Summary of Pricing and Inflation Rate Assumptions at December 31, 2012

Forecast Prices and Costs

Year	WTI @Cushing 40°API $US/bbl	Henry Hub Gas Price $US/MMbtu	Argentina Domestic Oil Price 40°API $US/bbl	Argentina Domestic Gas Price $US/ MMbtu
2013			76.91	3.80
2014			78.45	3.88
2015			80.02	3.95
2016			81.62	4.03
2017			83.25	4.11
2018			84.91	4.20
2019			86.61	4.28
2020			88.34	4.37
2021			90.11	4.45
2022			91.91	4.54
2023			93.75	4.63
2024			95.63	4.72
2025			97.54	4.82
2026			99.49	4.92
2027			101.48	5.02

Notes:

(1) Escalation at 2% per year after 2027.
(2) All costs escalate at 2% per year from 2013.
(3) Argentinean gas price represents industrial contract prices received in the area. Weighted average historical prices realized by the Corporation for year ended December 31, 2012 from its Argentina oil and gas properties was CDN$76.35/bbl for crude oil and CDN$4.16 for natural gas.
(4) Estimated future abandonment costs related to a working interest have been taken into account by Ryder Scott in determining reserves that should be attributed to a property and in determining the aggregate future net revenue therefrom, there was deducted the reasonable estimated future well abandonment costs. No allowance was made, however, for reclamation of wellsites or the abandonment of any facilities.
(5) The forecast price and cost assumptions assume the continuance of current laws and regulations.
(6) The extent and character of all factual data supplied to Ryder Scott were accepted by Ryder Scott as represented. No field inspection was conducted.

McDaniel employed the following pricing, exchange rate and inflation rate assumptions as of December 31, 2012 in the McDaniel Report in estimating reserves data using forecast prices and costs.

	Medium and Light Crude Oil			Natural Gas		NGL	
Year	WTI Cushing Oklahoma 40° API(1) (US$/bbl)	Edmonton Par Price 40° API(2) ($/bbl)	Cromer Medium 29.3° API(3) ($/bbl)	Alberta Gas Average Plantgate ($/MMBtu)	AECO - C Spot ($/MMBtu)	Edmonton NGL mix(4) ($/bbl)	Exchange Rate ($US/$Cdn)
2013	92.50	87.50	83.10	3.15	3.35	57.60	1.000
2014	92.50	90.50	86.00	3.65	3.85	63.40	1.000
2015	93.60	92.60	88.00	4.15	4.35	68.70	1.000
2016	95.50	94.50	89.80	4.50	4.70	70.40	1.000
2017	97.40	96.40	91.60	4.90	5.10	72.10	1.000
2018	99.40	98.30	93.40	5.25	5.45	73.80	1.000

	Medium and Light Crude Oil			Natural Gas		NGL	
Year	WTI Cushing Oklahoma 40° API(1) (US$/bbl)	Edmonton Par Price 40° API(2) ($/bbl)	Cromer Medium 29.3° API(3) ($/bbl)	Alberta Gas Average Plantgate ($/MMBtu)	AECO - C Spot ($/MMBtu)	Edmonton NGL mix(4) ($/bbl)	Exchange Rate ($US/$Cdn)
2019	101.40	100.30	95.30	5.30	5.55	75.30	1.000
2020	103.40	102.30	97.20	5.45	5.70	76.80	1.000
2021	105.40	104.30	99.10	5.55	5.80	78.30	1.000
2022	107.60	106.50	101.20	5.65	5.90	80.00	1.000
2023	109.70	108.50	103.10	5.75	6.00	81.50	1.000
2024	111.90	110.70	105.20	5.90	6.15	83.10	1.000
2025	114.10	112.90	107.30	6.00	6.25	84.80	1.000
2026(5)	116.40	115.20	109.40	6.10	6.35	86.50	1.000

Notes:

(1) West Texas Intermediate at Cushing Oklahoma 40 degrees API/0.5% sulphur
(2) Edmonton Light Sweet 40 degrees API, 0.3% sulphur
(3) Midale Cromer crude oil 29 degrees API, 2.0% sulphur
(4) NGL Mix based on 45 percent propane, 35 percent butane and 20 percent natural gasolines
(5) Escalated at 2%/yr. thereafter

The weighted average realized sales prices before hedging for the two months ended December 31, 2012 were $3.27/Mcf for natural gas, $70.29/Bbl for light and medium crude oil, $71.23/Bbl for heavy oil and $48.04/Bbl for NGLs. The unusual variation between light and medium crude versus heavy crude prices was a result of significantly lower prices received during the month of December for both grades of oil; however, heavy crude oil sales were 54 bopd in November 2012 compared to 28 bopd in November 2011.

Reconciliation of Changes in Reserves

Reconciliation of Gross Reserves by Principal Product Type

The following tables set out the reconciliation of the Corporation's gross reserves as at December 31, 2012 compared to December 31, 2011 based on forecast prices and costs by principal product type:

ARGENTINA FACTORS	--------- Light and Medium Crude Oil -----------			------------------ Natural Gas -----------------------		
	Proved (Mbbl)	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**	**Total Proved (Mmcf)**	**Total Probable (Mmcf)**	**Total Proved Plus Probable (Mmcf)**
December 31, 2011	702.6	563.0	1,265.7	1,025.7	769.7	1,795.4
Extensions	32.3	10.0	42.3	41.8	12.0	53.8
Improved Recovery						
Technical Revisions	(314.9)	(338.5)	(653.5)	(696.5)	(573.7)	(1,270.2)
Discoveries	28.0	19.1	47.1	7.1	4.8	11.9
Acquisitions						
Dispositions						
Prices						
Production	(56.8)		(56.8)	(54.4)		(54.4)
December 31, 2012	391.2	253.6	644.8	323.7	212.8	536.5

CANADA FACTORS	Light and Medium Crude Oil			Heavy Oil		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2011	-	-	-	-	-	-
Extensions	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
Acquisitions	291.8	249.2	541.1	48.1	5.4	53.5
Dispositions	-	-	-	-	-	-
Prices	-	-	-	-	-	-
Production	(8.8)		(8.8)	(3.1)		(3.1)
December 31, 2012	283.0	249.2	532.3	45.0	5.4	50.4

	Natural Gas Liquids			Natural Gas		
	Total Proved (Mbbl)	Total Probable (Mbbl)	Total Proved Plus Probable (Mbbl)	Total Proved (Mmcf)	Total Probable (Mmcf)	Total Proved Plus Probable (Mmcf)
December 31, 2011	-	-	-	-	-	-
Extensions	84.3	71.2	155.5	3,373.4	2,567.5	5,940.9
Improved Recovery	-	-	-	-	-	-
Technical Revisions	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
Acquisitions	314.6	111.5	426.2	4279.3	1909.6	6188.9
Dispositions	-	-	-	-	-	-
Prices	-	-	-	-	-	-
Production	(7.2)		(7.2)	(114.6)		(114.6)
December 31, 2012	391.7	182.7	574.5	7538.1	4477.1	12015.2

TOTAL FACTORS

	Light and Medium Crude Oil			Heavy Oil		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2011	702.6	563	1,265.7	-	-	-
Extensions	32.3	10	42.3	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions	(314.9)	(338.5)	(653.5)	-	-	-
Discoveries	28	19.1	47.1	-	-	-
Acquisitions	291.8	249.2	541.1	48.1	5.4	53.5
Dispositions	-	-	-	-	-	-
Prices	-	-	-	-	-	-
Production	(65.6)	0	(65.6)	(3.1)	0	(3.1)
December 31, 2012	674.2	502.8	1,177.1	45.0	5.4	50.4

	Natural Gas Liquids Total Proved (Mbbl)	Total Probable (Mbbl)	Total Proved Plus Probable (Mbbl)	Natural Gas Total Proved (Mmcf)	Total Probable (Mmcf)	Total Proved Plus Probable (Mmcf)
December 31, 2011	-	-	-	1,025.7	769.7	1,795.4
Extensions	84.3	71.2	155.5	3,415.2	2,579.5	5,994.7
Improved Recovery	-	-	-	-	-	-
Technical Revisions	-	-	-	(696.5)	(573.7)	(1,270.2)
Discoveries	-	-	-	7.1	4.8	11.9
Acquisitions	314.7	111.5	426.2	4279.3	1909.6	6188.9
Dispositions	-	-	-	-	-	-
Prices	-	-	-	-	-	-
Production	(7.2)	-	(7.2)	(169)	-	(169)
December 31, 2012	391.8	182.7	574.5	7861.8	4689.9	12551.7

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following tables set forth the remaining proved undeveloped reserves and the remaining probable undeveloped reserves, each by product type, attributed to the Corporation's assets for the years ended December 31, 2012, 2011 and 2010 and, in the aggregate, before that timed based on forecast prices and costs.

ARGENTINA

Proved Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Natural Gas (MMcf)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior thereto	181.7	181.7	181.3	181.3
2010	295.7	432.0	368.4	534.0
2011	123.2	351.1	265.7	570.3
2012	-	120.4	-	115.6

Probable Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Natural Gas (MMcf)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior thereto	326.5	326.5	397.1	397.1
2010	170.9	341.8	213.5	438.5
2011	92.4	320.3	124.7	432.4
2012	-	126.9	-	121.8

CANADA

Proved Undeveloped Reserves

Year	Light and Medium 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 thereto	-	-	-	-	-	-
2010	-	-	-	-	-	-
2011	-	-	-	-	-	-
2012	85.1	85.1	1,571.1	1,571.1	48.1	48.1

Probable Undeveloped Reserves

Year	Light and Medium 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 thereto	-	-	-	-	-	-
2010	-	-	-	-	-	-
2011	-	-	-	-	-	-
2012	138.9	138.9	2,336.6	2,336.6	65.7	65.7

TOTAL

Proved Undeveloped Reserves

Year	Light and Medium 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 thereto	181.7	181.7	181.3	181.3	-	-
2010	295.7	432	368.4	534	-	-
2011	123.2	351.1	265.7	570.3	-	-
2012	85.1	205.5	1,571.1	1,686.7	48.1	48.1

Probable Undeveloped Reserves

Year	Light and Medium 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 thereto	326.5	326.5	397.1	397.1	-	-
2010	170.9	341.8	213.5	438.5	-	-
2011	92.4	320.3	124.7	432.4	-	-
2012	138.9	265.8	2,336.6	2,458.4	65.7	65.7

Proved Undeveloped Reserves

The Corporation generally attributes proved undeveloped reserves to 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.

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. See "*Principal Properties*" and "*Statement of Reserves Data – Future Development* Costs" for a description of the Corporation's exploration and development plans and expenditures.

Significant Factors or Uncertainties

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering or economic data. These estimates may change substantially as additional data from ongoing development activities and production performance become available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions.

As circumstances change and additional data become available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices, and reservoir performance. Such revisions can either be positive or negative.

Future Development Costs

The table below sets out the development costs deducted in the estimation of future net revenue attributable to proved reserves (using forecasted prices and costs only) and proved plus probable reserves (using forecast prices and costs only).

ARGENTINA

US$	**Forecast Prices and Costs (MM)**	
Year	**Proved Reserves**	**Proved Plus Probable Reserves**
2013	3.2	3.6
2014	-	1.9
Total (Undiscounted)	3.2	5.5
Total (Discounted at 10%)	3.0	5.1

CANADA

CDN$	**Forecast Prices and Costs (MM)**	
Year	**Proved Reserves**	**Proved Plus Probable Reserves**
2013	10.2	13.8
2014	-	3.9
Total (Undiscounted)	10.2	17.7
Total (Discounted at 10%)	9.8	16.8

TOTAL

CDN$	Forecast Prices and Costs (MM)	
Year	**Proved Reserves**	**Proved Plus Probable Reserves**
2013	13.4	17.4
2014	-	5.8
Total (Undiscounted)	13.4	23.2
Total (Discounted at 10%)	12.8	21.9

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.

Madalena intends to use existing working capital, internally generated cash flow from operations, debt (if available on favourable terms), new equity issues (if available on favourable terms), and farm outs or similar arrangements to finance its capital expenditure program. The cost of funding could negatively affect disclosed reserves or future net revenue depending on the source and nature of the funding but the impact cannot readily be determined at this time. See "*Risk Factors*".

Other Oil and Gas Information

Oil and Natural Gas Wells

The following table sets forth the number and status of oil and natural gas wells in which Madalena has a working interest and which are producing or mechanically capable of producing and the wells which are not producing or mechanically capable of production as of December 31, 2012:

	Oil Wells		Natural Gas Wells		Non-producing Wells		Total	
Location	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Argentina	9	3.2	-	-	5	3.5	14	6.7
Canada	12	7.5	23	16.5	59	40.8	94	64.8
Total	21	10.7	23	16.5	64	44.3	108	71.5

Properties With No Attributed Reserves

The following table sets forth Madalena's undeveloped land position as at December 31, 2012:

	Gross		Net	
Location	**Acres**	**Sections**	**Acres**	**Sections**
Argentina, South America	278,522	435	134,180	210
Alberta, Canada	95,213	149	84,175	132

In March 2012 an application by the Coiron Amargo joint venture to convert the northern 108 km^2 of the 404 km^2 Coiron Amargo Block to a 25 year exploitation concession was approved by the Province of Neuquén. In addition, the exploration period for the remainder of the Coiron Amargo Block (i.e. southern portion of the block) was extended to November 8, 2013. The extension of the Coiron Amargo Block will require additional exploration work commitments in the south of US$33.5 million (Madalena share – US$13.0 million of which approximately US$4.9 million plus VAT remains outstanding).

In March 2012 the exploration period for the Curamhuele Block was extended to November 8, 2013. The extension of the block required additional work commitments of US$17.6 million (Madalena share – US$17.6 million of which approximately US$14.1 million plus VAT remains outstanding). The exploration block qualifies for an additional one year extension period at the end of the exploration period in the fourth quarter of 2013. As of December 2012 and throughout the first quarter of 2013, Madalena has been working to qualify the Curamhuele Block for an additional one year extension.

The initial exploration period on the Cortadera Block in the Province of Neuquén had an initial expiry of October 26, 2011, in and around which time a new proposal was made by the joint venture to formalize an extension of the initial exploration period based on a proposed work plan for the block. As of December 2012, the original proposal was yet to be finalized with provincial authorities and discussions by the joint venture were reopened with the decision to submit a new proposal. In the first quarter of 2013, the joint venture submitted a revised proposal and is currently working to progress and finalize an agreed to work program for the block.

Provided the Corporation has met its block work commitments by the expiry dates, the Corporation expects to either convert all or a portion of its acreage to a 25 year exploitation concession, receive an extension or enter into a new exploration period, with or without additional work commitments, of its rights to explore, develop and exploit such undeveloped properties.

Forward Contracts and Marketing

As of the date hereof, the Corporation has the following physical natural gas and oil contracts in place:

Type	Period	Volume	Price Floor	Price Ceiling	Index
Natural gas fixed	April 1, 2013 to Oct. 31, 2013	300 GJ/d	$3.00 CDN	$3.00 CDN	AECO
Natural gas fixed	April 1, 2013 to Oct. 31, 2013	300 GJ/d	$3.20 CDN	$3.20 CDN	AECO
Natural gas fixed	April 1, 2013 to Oct. 31, 2013	300 GJ/d	$4.47CDN	$4.47 CDN	AECO
Crude oil call options	Jan. 1, 2014 to Dec. 31, 2014	50 bbl/d	-	$100.00 US	WTI

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 Engineers Reports as a deduction in determining future net revenue. The Corporation 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 abandonment and reclamation obligation included in the Corporation's financial statements differs from the amount deducted in the reserves evaluation, as no allowance was made for reclamation of well sites in the Reserves Reports. In addition, the financial statements include abandonment and reclamation obligations for both facilities and wells that were not assigned year-end reserves, neither of which are included in the Reserves Reports.

The total estimated abandonment costs in respect of the Argentina reserves is $2.6 million undiscounted based on an inflation rate of 14.7% ($0.6 million using a 10.8% discount rate). The Corporation has 14 gross (6.7 net) wells for which it expects to incur abandonment costs.

The following table indicates the expected timing of well abandonment and sets forth abandonment costs deducted in the estimation of the Corporation's future net revenue for the Coiron Amargo Block:

Forecast Prices and Costs	**Argentina Abandonment Costs (Undiscounted) US M$**	
Year	**Total Proved**	**Total Proved Plus Probable**
2023	469.3	-
Remainder	-	554.2
Total Undiscounted	469.3	554.2
Total Discounted @ 10%	157.0	124.5

The total estimated abandonment costs in respect of proved plus probable reserves using forecast prices is $4.4 million undiscounted ($1.2 million using a 10% discount rate) for Canada. The Corporation has 94 gross (68 net) wells for which it expects to incur abandonment costs

Canada **($CDN - 000s)**	**Proved Plus Probable Abandonment and Reclamation Costs Escalated at 2% Undiscounted SMM**	**Proved Plus Probable Abandonment and Reclamation Costs Escalated at 2% Discounted at 10% $MM**
Abandonment costs associated with wells that have assigned reserves [(1)]	1.2	0.4
Reclamation costs associated with wells that have assigned reserves [(1)]	0.5	0.2
Abandonment and reclamation costs associated with non-producing, shut-in and wells that have no assigned reserves [(1)]	2.7	0.8
Total abandonment and reclamation costs provision	4.4	1.4
Portion forecast to be paid during the next three years	0.1	0.1

Note:

(1) The Corporation has taken abandonment costs from the McDaniel Report (proved plus probable forecast) for wells that have reserves. Internal estimates were used for abandonment costs for wells that do not have reserves and surface reclamation costs for all wells. The internal estimates have not been deducted in estimating the future net revenue.

Tax Horizon

Depending on production, commodity prices and capital spending levels, management believes that the Corporation will not have taxes payable in the immediate future as there are sufficient tax pools available to reduce future taxable income.

Costs Incurred

The following table summarizes capital expenditures (net of asset retirement costs, foreign exchange gains or losses and office equipment) related to the Corporation's activities for the year ended December 31, 2012:

	Argentina $CDN - MM	**Canada $CDN - MM**	**Total $CDN - MM**
Property acquisition costs:			
Proved Properties	-	21.5	21.5
Undeveloped Properties	-	3.5	3.5
Exploration costs	9.4	2.1	11.5
Development costs	8.7	2.5	11.2
Total	18.1	29.6	47.7

Exploration and Development Activities

Argentina

On Coiron Amargo Sur, in February 2012 the Corporation drilled and cased the CAS X-4 well approximately nine kilometers south east of the CAS X-1 discovery well drilled in 2011 and in March 2012 drilled and cased to TD the CAS X-2 vertical exploration well in the center of the block. At CAS X-4 a full diameter core was taken through most of the Vaca Muerta shale formation interval which will be used to optimize future wells in the Vaca Muerta formation.

On Coiron Amargo Norte, in May 2012 the Corporation completed drilling the CAN 5 development well located within the CAN X-1 Sierras Blancas structure and in June 2012 the Corporation completed drilling the CAN 7 development well located within the CAN X-3 Sierras Blancas structure.

In November 2012, the Corporation commenced drilling the CAN 8 development well located approximately 800 metres south east of the CAN 7 well. The vertical well is scheduled to be drilled to approximately 10,430 feet depth with the primary objective horizon in the Sierras Blancas formation and the Vaca Muerta horizon above.

On Cortadera, at no cost to the Corporation, Apache completed a two stage hydraulic fracture stimulation of the Vaca Muerta formation in the CorS X-1 vertical exploration well.

At Curamhuele, the Cur X-1 well the Corporation mobilized a service rig in the second quarter of 2012 for its planned three stage fracture stimulation of the Lower Agrio shale formation. At this time operations on the CurX-1 well remain suspended after attempts to remove certain down-hole equipment in order to install casing for the fracture stimulation were unsuccessful.

Canada

On November 1, 2012 the Corporation acquired all of the common shares of ONL for a total purchase price of approximately $20.6 million which includes the assumption of Online's debt in the amount of approximately $5.5 million. Online's assets include 153 net sections of land (197 gross sections at 77.9% average working interest) in the greater Paddle River area of central Alberta across multiple light oil and liquids-rich gas resource plays. The acquisition of Online provides entry into the domestic E&P space with the opportunity to increase production and cash flow while continuing to develop and grow its international assets & business plan.

In late 2012, the Corporation drilled and cased a horizontal well at Niton that was completed and put on-stream in early March of 2013. The Corporation also commenced the drilling of a Nordegg horizontal well in the Wildwood area in late 2012. This well was still drilling at year-end.

Production Estimates

The following table sets out the volume of the Corporation's gross working interest production estimated for the year ended December 31, 2013 as evaluated by the Reserve Engineers which is reflected in the estimate of future net revenue disclosed in the tables contained under "*Disclosure of Reserves Data and Other Information*".

	Light and Medium Oil *(Bopd)*	**Heavy Oil** *(Bopdl)*	**Natural Gas** *(Mcf/d)*	**Natural Gas Liquids** *(Bbls/d)*	**BOE** *(Boe/d)*
Total Proved					
Argentina	227	-	200	-	260
Canada	196	22	2,900	140	841
	423	22	3,100	140	1,001
Total Probable					
Argentina	30	-	25	-	34
Canada	30	-	275	12	88
	60	-	360	12	132
Total Proved Plus Probable					
Argentina	257	-	285	-	304
Canada	226	22	3,175	152	929
	583	22	3,460	152	1,233

Production History

Madalena's daily production, before royalties, on a quarterly basis and for the year ended December 31, 2012 is summarized below:

ARGENTINA

Production

	Q4 2012	Q3 2012	Q2 2012	Q1 2012
Light and medium oil – Bbls/d	195	250	54	56
Heavy oil – Bbls/d	-	-	-	-
Natural gas – Mcf/d	132	84	-	-
Natural gas liquids – Bbls/d	-	-	-	-
Total production – BOE/d	**217**	**264**	**54**	**56**

The following table discloses, on a quarterly basis, the prices received, royalties paid, production costs incurred and netbacks on a $ per BOE basis for oil wells (including associated solution gas).

Netbacks

$ per BOE	Q4 2012	Q3 2012	Q2 2012	Q1 2012
Prices Received	72.19	72.52	76.64	77.19
Royalties Paid	(10.46)	(11.27)	(11.60)	(13.58)
Production Costs	(32.79)	(26.10)	(55.47)	(64.23)
Netback	**28.94**	**35.15**	**9.57**	**(0.62)**

Prices Received

The following table discloses, on a quarterly basis and for the year ended December 31, 2012, the prices received by product type.

	Q4 2012	Q3 2012	Q2 2012	Q1 2012
Light and medium crude oil - $/Bbl	77.63	75.11	76.64	77.19
Natural gas - $/Mcf	4.03	4.38	-	-

CANADA

Production

	Q4 2012	Q3 2012	Q2 2012	Q1 2012
Light and medium oil – Bbls/d	104	-	-	-
Heavy oil – Bbls/d	27	-	-	-
Natural gas – Mcf/d	1,245	-	-	-
Natural gas liquids – Bbls/d	78	-	-	-
Total production – BOE/d	**417**	-	-	-

The majority of the Canadian production produces natural gas and natural gas liquids or crude oil and solution gas. Wells that produce natural gas and natural gas liquids are classified as natural gas wells. Wells that produce both natural gas and crude oil are categorized as either a natural gas well or an oil well based upon the proportion of natural gas production to crude oil production. The following tables disclose, on a quarterly basis, the prices received, royalties paid, production costs incurred and netbacks on a $ per BOE basis for oil wells (includes the natural gas production associated with the oil wells converted to

BOE at 6 Mcf:1Bbl) and on a $ per Mcfe basis for gas wells (includes the oil and natural gas liquids production associated with the natural gas wells converted to Mcfe at 1Bbl:6 Mcf).

Netbacks - oil

$ per BOE	**Q4 2012**	**Q3 2012**	**Q2 2012**	**Q1 2012**
Prices Received	51.24	-	-	-
Royalties Paid	(11.46)	-	-	-
Production Costs	(30.55)	-	-	-
Netback	**9.23**	-	-	-

Netbacks – natural gas

$ per Mcfe	**Q4 2012**	**Q3 2012**	**Q2 2012**	**Q1 2012**
Prices Received	4.78	-	-	-
Royalties Paid	(0.44)	-	-	-
Production Costs	(4.28)	-	-	-
Netback	**0.06**	-	-	-

CANADA	**Q4 2012**	**Q3 2012**	**Q2 2012**	**Q1 2012**
Light and medium crude oil - $/Bbl	70.29	3.95	3.78	3.25
Heavy oil - $/Bbl	71.23	99.88	81.14	91.37
Natural gas - $/Mcf	3.27	89.05	75.87	84.90
NGLs - $/Bbl	48.04	63.59	58.43	65.92

Production Volume by Field

The following table discloses for each important field, and in total, the Corporation's production volumes for the financial year ended December 31, 2012 for each product type. The production for Canada is the sum of the months of November and December divided by the full year of 2012.

Field	**Light and Medium Crude Oil (Bbls/d)**	**Heavy Oil (Bbls/d)**	**Natural Gas (Mcf/d)**	**Natural Gas Liquids (Bbls/d)**	**BOE (BOE/D)**	**%**
Canada						
Greater Paddle River	26	7	314	20	105	40%
Argentina	149	-	55	29	155	60%
Total	**175**	**7**	**369**	**58**	**260**	**100%**

DIVIDEND POLICY

The Corporation has not paid any dividends or distributions on the Common Shares. The Board will determine the timing, payment and amount of future dividends, if any, that may be paid by the Corporation from time to time based upon, among other things, the cash flow, results of operations and financial condition of the Corporation, the need for funds to finance ongoing operations and other business considerations as the Board considers relevant.

DESCRIPTION OF CAPITAL STRUCTURE

The Corporation is authorized to issue an unlimited number of Common Shares without nominal or par value. As at May 2, 2013, there were 316,090,885 Common Shares issued and outstanding. In addition, as at such date, there were an aggregate of 17,929,999 Common Shares reserved for issuance upon the exercise of outstanding options to purchase Common Shares ("**Options**").

Each Common Share entitles its holder to receive notice of and to attend all meetings of the shareholders of the Corporation and to one vote at such meetings. The holders of Common Shares are, at the discretion of the Board 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 Corporation 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 Corporation upon the liquidation, dissolution, bankruptcy or winding-up of the Corporation 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 Corporation ranking in priority to the Common Shares.

MARKET FOR SECURITIES

The Common Shares trade on the TSXV under the symbol "MVN".

The following table sets forth the price range and volume of the Common Shares as reported by the TSXV during the year-ended December 31, 2012:

Period	High ($)	Low ($)	Volume
2012			
January	1.28	0.86	41,663,426
February	1.41	1.07	74,799,562
March	1.26	0.87	44,340,075
April	0.95	0.45	72,388,230
May	0.60	0.35	12,406,835
June	0.51	0.295	15,474,389
July	0.42	0.315	12,300,352
August	0.33	0.26	16,091,554
September	0.31	0.20	20,516,586
October	0.30	0.225	9,352,211
November	0.295	0.20	17,354,710
December	0.39	0.215	29,687,833

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTIONS ON TRANSFER

As of the date hereof, no securities of the Corporation are subject to escrow or contractual restrictions on transfer.

PRIOR SALES

The following table summarizes the issuances of securities convertible into Common Shares issued during the year-ended December 31, 2012:

Date	Securities	Number of Securities	Price per Security
January 9, 2012	Issuance of Options	10,000	$0.69
January 9, 2012	Issuance of Options	8,333	$0.80
February 10, 2012	Issuance of Options	13,333	$0.105
February 17, 2012	Issuance of Options	166,666	$0.73
March 7, 2012	Common shares	54,000,000	$1.25
March 27, 2012	Issuance of Options	13,334	$0.105
March 27, 2012	Issuance of Options	16,667	$0.21
March 28, 2012	Issuance of Options	25,000	$0.69
March 28, 2012	Issuance of Options	33,334	$0.80

Notes:

(1) On March 7, 2012, Madalena closed an offering pursuant to which it issued 54,000,000 Common Shares at an issue price of $1.25 per Common Share, including 6,000,000 Common Shares pursuant to the exercise in full of the over-allotment option, for aggregate gross proceeds of $67,500,000.

(2) Reflects the exercise price of such Options.

DIRECTORS AND OFFICERS

The name and place of residence of each director and officer, the offices held by each in the Corporation, and the principal occupation of the directors and officers, the period served as director and the number of securities of the Corporation owned by such individuals as at May 2, 2013 is as follows:

Name, Address and Position	Principal Occupation for the Previous 5 Years	Director Since	Number of Common Shares
Kevin Shaw Alberta, Canada Director / President /Chief Executive Officer	Currently the President and Chief Executive Officer of Madalena. Prior thereto, Managing Director & Head of Global Energy Research at Casimir Capital from August 2011 to November 2012. Previously, Wellington West Capital Markets as a Senior Oil & Gas Research Analyst and Partner from 2009 to July 2011. Prior to holding executive positions within the Capital Markets, Mr. Shaw was Alliance Manager for Colt WorleyParsons, Vice President, Operations for Trimox Energy Inc. and held various technical & managerial roles with ExxonMobil. Kevin is a Professional Engineer and holds a B.Sc. in Mechanical & Petroleum Engineering from the University of Calgary and an MBA from the Haskayne School of Business.	November 27, 2012	500,000
Ray Smith California, USA Director /Chairman (4)	Currently Chairman of the Board of Madalena and President, CEO and Director of Bellatrix Exploration Ltd. 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)	Currently President of Upsilon Holdings Ltd., a privately owned consulting company.	December 29, 2005	460,000(1)(2)
Keith Macdonald Alberta, Canada Director (4)(5)(6)	Currently President of Bamako Investment Management Ltd., a privately owned investment and financial advisory company.	June 22, 2010	440,000
Ving Woo Alberta, Canada Director (5)(6)	Currently Vice President and Chief Operating Officer at Bellatrix Exploration Ltd., since April 2009. 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 Apri12002. Formerly Vice President, Engineering for New Cache Petroleum from February 1996 until February 1999.	March 10, 2006	1,525,000

Name, Address and Position	Principal Occupation for the Previous 5 Years	Director Since	Number of Common Shares
Jay Reid Alberta, Canada Director (4)	Partner at the Calgary based law firm of Burnet, Duckworth & Palmer LLP and has practiced corporate and securities law since 1990. He has served as a director or officer of a number of publicly listed issuers and currently serves as a Director of Renegade Petroleum Ltd. and Madalena Ventures Inc. and Corporate Secretary for Advantage Oil & Gas Ltd., Longview Oil Corp., TriOil Resources Ltd. and Pinecrest Energy Inc. and also serves as a director or corporate secretary of six private issuers.	February 13, 2009	Nil
Barry B. Larson Alberta, Canada Director (6)	Currently Vice President Operations and Chief Operating Officer of Parex Resources Inc. since September, 2009. Prior thereto Vice President Operations and Chief Operating Officer of Petro Andina Resources Inc. from February 2005 to September, 2009.	July 21, 2010	Nil
Steve Dabner Alberta, Canada	Currently Vice President – Exploration of Madalena. Previously, President, Chief Executive Officer and Director of Online from January 2011 to October 2012. Prior thereto, independent businessman from June 2007 – January, 2011 and President, Chief Executive Officer and Director of Trimox Energy Inc. from December 2004 until June 2007.	N/A	500,000
Brent Foster Alberta, Canada	Currently Vice President – Engineering of Madalena Previously, Vice President, Engineering of Online Energy Inc. from January 2011 to October 2012. Prior thereto, independent businessman from 2010 to January 2011, consultant to Intrepid Energy Corp. and EdgeStone Capital Partners from 2007 – 2010 and co-founder, Vice-President, Engineering and COO of Blue Mountain Energy Ltd. from 2002 – 2006.	N/A	Nil
Robert D. Stanton Alberta, Canada	Currently Vice President – Operations of Madalena Previously, Vice President, Operations of Online Energy Inc. from January 2011 to October 2012. Prior thereto, independent businessman from November 2009 to January 26, 2011 and Vice-President, Engineering and Operations of Result Energy Inc. from January 2005 to November 2009.	N/A	Nil
Thomas Love Alberta, Canada	Currently Vice President – Finance and Chief Financial Officer of Madalena. Previously, Chief Financial Officer and Director of Online Energy Inc. from January 2011 to October 2012. Prior thereto, independent businessman from June 2007 – January 26, 2011 and Chairman, Chief Financial Officer and Director of Trimox Energy Inc. from December 2004 until June 2007.	N/A	Nil

Notes:

(1) Ms. Kathryn Lock, the spouse of Mike Lock, holds directly 500,000 Common Shares,
(2) Member of the Audit Committee.
(3) Member of the Corporate Governance and Compensation Committee.
(4) Member of the Audit Committee.
(5) Member of the Reserves Committee.
(6) Each director of the Corporation holds office from the time elected until the next annual meeting of shareholders at which time they shall retire but, if qualified, shall be eligible for re-election in accordance with the ABCA.

The directors and officers of the Corporation as a group own, directly or indirectly, or control or exercise direction over 8,396,500 Common Shares, representing 2.7% of the issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Other than as set out below, to the knowledge of the Corporation, no director or executive officer of the Corporation: (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 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, that was issued after the director of executive officer ceased to be a director of officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer, 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.

To the knowledge of the Corporation, no director or officer of the Corporation, or a shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, 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 Corporation will be subject in connection with the operations of the Corporation. In particular, certain of the directors and officers of the Corporation 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 Corporation or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of the Corporation. 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. See "*Risk Factors*".

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

As at the date of this AIF, there are no outstanding legal proceedings material to the Corporation to which the Corporation is a party or in respect of which any of its properties are subject, nor are there any such proceedings known to be contemplated except as follows:

On December 19, 2012, Online Energy Inc. as plaintiff filed a statement of claim with the Court of Queen’s Bench of Alberta. The named defendant is Import Tool Corporation Ltd. The claim alleges that the defendant, among other things, provided and installed improperly sized downhole tools in an Online horizontal well at Paddle River in the spring of 2012. Judgement is being sought in the amount of $720,671. On January 31, 2013, Import Tool Corporation Ltd. filed a statement of defense with the Court of Queen’s Bench of Alberta. On February 25, 2013, Online Energy Inc. filed a statement of defense to counterclaim with the Court of Queen’s Bench of Alberta. Online is currently preparing to file an affidavit of records in support of this claim.

In addition, there were no penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority during the 2012 financial year, no other penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision, and no settlement agreements entered into by the Corporation with a court relating to securities legislation or with a securities regulatory authority during the 2012 financial year.

TRANSFER AGENT AND REGISTRAR

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

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government and with respect to the pricing and taxation of oil and natural gas through agreements among the governments of jurisdictions in which the Corporation operates and/or owns properties, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these regulations or controls will affect the Corporation's operations in a manner materially different than they will affect other oil and natural gas companies of similar size with operations in Argentina and Canada. All current legislation is a matter of public record and the Corporation 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 in Argentina and Alberta, Canada.

Argentina

Pricing and Marketing

The Federal Government of Argentina has implemented controls for domestic fuel prices and has placed a tax on oil and natural gas exports. Industry-wide, government-mandated wellhead price controls in Argentina were abandoned in 1989 when the oil and natural gas industry, dominated by Yacimientos Petroliferos Fiscales S.E. ("**YPF**"), was privatized. Price controls were eliminated in 1991 and prices remained unregulated until the economic crisis in late 2001. At that time, contracts for natural gas sales were converted from U.S. dollars to Argentinean Pesos, concurrent with devaluation of the Argentinean Peso to US$0.33. Since that time, natural gas prices for sales to consumers through local distribution companies have remained fixed and commercial sales prices are set by the market. The Federal Government of Argentina has indicated some flexibility with respect to natural gas price deregulation and this has resulted in improved prices at the wellhead.

In August 2004, a progressive increase in export tax was instituted in Argentina on oil with reference to the price of WTI per barrel as quoted on the New York Mercantile Exchange ("**NYMEX**"). At WTI prices greater than US$32 per barrel, a tax was applied ranging from 25 percent up to 45 percent depending on the price of WTI. An amount equivalent to the export tax was applied to domestic sales. In November 2007, changes to the export tax were imposed with the objective of limiting the maximum price of oil that producers could receive for crude oil exports to US$42/bbl.

At the end of 2008, the Argentinean government launched the Gas Plus and Petroleum Plus programs, new programs designed to stimulate investments in and production of natural gas and oil through providing incentives for new production of natural gas or oil, either from new discoveries, enhanced recovery techniques or reactivation of older fields.

The Government of Argentina has recently announced that the Oil Plus programme has been replaced with oil exporters now receiving $70/bbl cash instead of the previous $42/bbl cash price plus an oil credit. Although most (approximately 90%) of the country’s oil production is sold into the domestic market, this move by the Argentina government signifies improvements and simplifications to certain commercial arrangements and is aimed at incentivizing further investment. Madalena currently sells all of its production into the domestic market and receives competitive prices in comparison to this export market. While management of the Corporation does not have any arrangements or current plans to export production, any future changes to the oil and gas pricing mechanisms in Argentina could have a material effect (positive or negative) directly or indirectly on the Corporation.

For a description of the prices and netbacks achieved by the Corporation during the year ended December 31, 2012, see "*Statement of Reserves Data and Other Oil and Gas Information - Other Oil and Gas Information - Production History*".

Pipeline Capacity

Argentina's three major oil pipelines originate at Puerto Hernandez, in the Neuquén Basin. Two pipelines are domestic, transporting oil north via the Repsol-YPF operated 50,000 bopd pipeline to the Lujan de Cuyo refinery near Mendoza and east via the Oldelval pipeline system moving crude over 1,200 kilometres to Puerto Rosales on the Atlantic. The 430 km, 115,000 bopd Transandino pipeline is Argentina's only international oil pipeline, climbing over the Andes Mountains to a refinery in Chile. This pipeline discontinued transportation of oil in 2006 but is capable of being recommissioned.

Downstream

Repsol-YPF accounts for approximately half of the country's (624,575) bopd total refining capacity. Other companies with significant refining capacity include Shell CAPSA Limited (110,000 bopd) and Esso Petrolera Argentina S.R.L. (84,500 bopd).

Due to increasing demand for natural gas, Argentina has been importing increased quantities of liquefied natural gas ("**LNG**") through the Bahia Blanca LNG terminal located approximately 600 km southwest of Buenos Aires. A second import terminal (Puerto Escobar) came on stream in June 2011 which more than doubled import capacity to 900 MMcf/d.

Relationships with Unions

Oil and gas activity in Argentina is largely unionized and drilling, completions and work over operations may be conducted by drilling operators employing unionized personnel. Accordingly, the Corporation is exposed to union activity including strikes, shut-downs, labour negotiations and other actions outside of the Corporation's direct control, which may have a material adverse effect on the operations of the Corporation.

Royalties, Turnover Taxes & Value Added Tax

Royalty determinations in Argentina are paid monthly to provincial authorities and must be submitted by field and concession. Production used by the concession holder for exploration or production operations is not subject to royalty. Royalties are deductible for income tax purposes. The standard royalty rate on production is 12 percent of the wellhead price for both oil and natural gas less deductions for transportation, treatment and commercialization costs between the wellhead and point of sale. This may be reduced on a case-by-case basis to a minimum of five percent taking into account productivity (marginal fields), condition and location of the producing wells as well as enhanced oil recovery projects. A rate of 15 percent applies to pre-commercial production from an exploration concession until such time as it is converted to an exploitation concession. In recent provincial bid rounds, companies have been given the option of bidding a higher royalty than prescribed by the national and provincial laws, but this is a voluntary decision which is applicable to the concession under bid only.

Additionally, the provinces levy a turnover tax varying between one and three percent of gross revenue less certain deductions. The turnover tax in Neuquén Province is 3%. A value added tax ("**VAT**") at a rate of 21 percent is added on to domestic sales and is payable by the buyers of production. The VAT collected by the Corporation on sales is used to recover VAT paid on incurred costs. Stamp taxes are levied on transactions by way of contract at one percent to four percent depending on the jurisdiction in which the transaction takes place.

Income Taxes

A tax treaty exists between Argentina and Canada. Oil companies are subject to a generally applicable corporate tax regime. All successful exploration and field development costs, including intangible costs may be depreciated on a unit-of-production basis. Tax payers pay either income tax at a rate of 35 percent on corporate net profits or a minimum tax, based on net assets, whichever is the greater. Minimum tax was reinstated effective January 1999 and is levied on cumulative capital less accumulated depreciation plus an inflation adjustment at a rate of one percent. In April 1992, the tax base for locally incorporated companies was changed from Argentinean source income to worldwide income.

Madalena is unaware of any prevailing currency restrictions with respect to repatriating after tax income from Argentina.

Oil and Gas Industry Regulations

The oil and natural gas industries in Argentina are subject to extensive regulation governing 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 federal and provincial governments, all of which are subject to change and could have a material impact on the Corporation's business, financial condition and results of operations. Any change to these government imposed restrictions could have a material impact on Madalena's business, financial condition and results of operations.

The Hydrocarbons Law 17.319, enacted in June 1967, established the basic legal framework for the current regulation of exploration and production of hydrocarbons in Argentina. The Hydrocarbons Law empowers the National Executive to establish a national policy for development of Argentina's hydrocarbon reserves, with the main purpose of satisfying domestic demand. However, on January 5, 2007, Hydrocarbon Law 26.197 was passed by the Government of Argentina ("**Ley Corta**"). This new legal framework replaces article one of the Hydrocarbons Law 17.319 and provides for the provinces to assume complete ownership, authority and administration of the oil and natural gas reserves located within their territories, including offshore areas up to 12 marine miles from the coast line. This includes all exploration, exploitation and transportation concessions. This has led to the posting of large tracts of exploration acreage in "bidding rounds" through which the lands are granted to successful bidding companies. The change of hydrocarbons administration has required producing companies to deal more extensively with the provincial governments who are now more directly involved in the day to day affairs of operations within their jurisdictions.

Land Tenure

Exploration permits in Argentina grant exclusive rights to the concession holder to perform all types of exploration work and obtain an exploitation concession and a transportation concession after the declaration of a commercial discovery. The period under an exploration permit is divided into several phases. Work commitments are negotiated and specified separately for each individual phase of the exploration period. For the first exploration phase, commitments may be expressed in work units with each activity equating to a different number of units. For the second and third exploration phases, commitments must comprise at least one well for each phase. Unless renegotiated, at the end of each exploration phase 50 percent of the remaining area must be relinquished or converted into an exploitation or evaluation concession. An evaluation concession allows a short term extension for a company to further evaluate the commercial potential of its exploration activities.

Exploitation concessions grant exclusive rights to the concession holder to produce hydrocarbons in areas of up to 250 km^2. The period for development and production is 25 years, although an extension of up to 10 years may be granted under terms and conditions to be established at the time of the extension. If a discovery is declared commercial before the end of the exploration period, the remaining portion of the exploration period is added on to the exploitation concession period.

Companies are permitted to hold, as operator, a maximum of five exploration permits in Argentina, but there is no limit on exploitation concessions.

Environmental Regulations

The oil and natural gas industry in Argentina is currently subject to environmental regulations pursuant to a variety of pieces of legislation, all of which is subject to governmental review and revision from time to time. 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, such as sulphur dioxide and nitrous oxide. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of government 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.

Specifically, Argentina has environmental standards for the industry, including surface maintenance and restoration, air quality and emission standards, operational safety standards and regular environmental audits. The implementation of environmental procedures is effected increasingly at the provincial level. A number of provinces have issued regulations relating to environmental impact assessments of activities within their boundaries.

Madalena conducted a thorough baseline environmental study of its acreage when it entered into its joint venture agreements and prior to commencing operations. Environmental reviews are completed and environmental permits are obtained from the provincial authorities prior to undertaking any operations.

Climate Change Regulation

Argentina ratified the Kyoto Protocol ("**Kyoto Protocol**"), which requires a reduction in greenhouse gas ("**GHG**") emissions by signatory countries between 2008 and 2012. The Kyoto Protocol officially came into force on February 16, 2005 and commits Argentina to reduce its GHG emissions levels to 6% below 1990 "business as usual" levels by 2012.

The United Nations Framework Convention on Climate Change is working towards establishing a successor to the Kyoto Protocol. From December 7 to 18, 2009, government leaders and representatives met in Copenhagen, Denmark and agreed to the Copenhagen Accord, which reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. Another meeting of government leaders and representatives in 2010 resulted in the Cancun Agreements wherein developed countries committed to additional measures to help developing countries deal with climate change. Neither the Copenhagen Accord nor the Cancun Agreements establish binding GHG emissions reduction targets.

Legal & Political

Argentina is governed by a tripartite system of government made up of an Executive Power, a Legislative Power, and a Judicial Power established by a written Constitution passed in 1853. The Head of Government and Chief of State is a President elected by popular vote for a term of four years. The Argentinean Republic comprises 23 provinces and the City of Buenos Aires. Each province has its own constitution, which must state its administration of justice and municipal autonomy and the scope and content of its institutional, political, administrative and financial orders.

Market Conditions

Overview

The oil and natural gas industry in Argentina is mature, having been established more than 100 years ago on December 13, 1907 when oil was discovered in Comodoro Rivadavia. While Argentina is a significant South American energy producer and consumer, in recent years it has become a net importer of refined products and natural gas liquids.

The Federal Government of Argentina has implemented controls for domestic fuel prices and has placed a tax on oil and natural gas exports. As a result of market uncertainty, energy reinvestment has been limited and overall hydrocarbon production has declined.

Exploration & Production

Two onshore basins represent the vast majority of Argentina's oil production: the Neuquén Basin, located in western-central Argentina, and the Gulf of San Jorge, in the southeast part of the country. Outside the established onshore basins, there has been some limited interest in exploring offshore oil resources. The Neuquén, Salta, Tierra del Fuego, and Santa Cruz regions contain most of Argentina's natural gas production, with the Neuquén region accounting for over half of the country's total production.

Availability of Services

There is a high utilization rate in the country for drilling rigs and other equipment. Recently, there has also been considerable interest in Argentina's shale oil and shale gas potential which in order to be developed will require oil and gas service companies operating in the country to develop or procure additional specialized equipment and expertise.

Alberta

Pricing and Marketing

Oil

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. Worldwide supply and demand primarily determines oil prices. The specific price depends in part on oil quality, prices of competing fuels, distance to market, the availability of transportation, the value of refined products, the supply/demand balance and contractual terms of sale. 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. The NEB is currently undergoing a consultation process to update the current regulations governing the issuance of export licences. The updating process is necessary to meet the criteria set out in the federal *Jobs, Growth and Long-term Prosperity Act* which received Royal Assent on June 29, 2012 (the "**Prosperity Act**"). In this transitory period, the NEB has issued, and is currently following an "Interim Memorandum of Guidance concerning Oil and Gas Export Applications and Gas Import Applications under Part VI of the *National Energy Board Act*".

Natural Gas

Alberta's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system such as the Alberta "NIT" (Nova Inventory Transfer), at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange (NGX) or the New York Mercantile Exchange (NYMEX) in the United States, spot and future prices can be set by such supply and demand. 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 for a larger quantity requires an exporter to obtain an export licence from the NEB.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico became effective on January 1, 1994. 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 the total supply of goods of the party maintaining the restriction as compared to 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 measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply.

All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings. NAFTA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports. NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates and other matters. The royalty regime in a given province 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 negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of 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 carved out of the working interest owner's interest, from time to time, 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 or royalty tax credits and are generally introduced when commodity prices are low to encourage exploration and development activity by improving earnings and cash flow within the industry.

Alberta

Producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, currently at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced.

Royalties are currently paid pursuant to "*The New Royalty Framework*" (implemented by the Mines and Minerals (New Royalty Framework) Amendment Act, 2008) and the "*Alberta Royalty Framework*", which was implemented in 2010.

Royalty rates for conventional oil are set by a single sliding rate formula, which is applied monthly and incorporates separate variables to account for production rates and market prices. Effective January 1, 2011, the maximum royalty payable under the royalty regime was set at 40%. The royalty curve for conventional oil announced on May 27, 2010 amends the price component of the conventional oil royalty formula to moderate the increase in the royalty rate at prices higher than $535/m3 compared to the previous royalty curve.

Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Effective January 1, 2011, the maximum royalty payable under the royalty regime was set at 36%. The royalty curve for natural gas announced on May 27, 2010 amends the price component of the natural gas royalty formula to moderate the increase in the royalty rate at prices higher than $5.25/GJ compared to the previous royalty curve.

Producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold production taxes. The level of the freehold production tax is based on the volume of monthly production and a specified rate of tax for both oil and gas.

The Innovative Energy Technologies Program (the "**IETP**"), which is currently in place, has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The IETP provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

The Government of Alberta currently has in place two royalty programs, both of which commenced in 2008 with the intention to encourage the development of deeper, higher cost oil and gas reserves. A five-year program for conventional oil exploration wells over 2,000 metres provides qualifying wells with up to a $1 million or 12 months of royalty relief, whichever comes first, and a five-year program for natural gas wells deeper than 2,500 metres provides a sliding scale royalty credit based on depth of up to $3,750 per metre. On May 27, 2010, the natural gas deep drilling program was amended, retroactive to May 1, 2010, by reducing the minimum qualifying depth to 2,000 metres, removing a supplemental benefit of $875,000 for wells exceeding 4,000 metres that are spudded subsequent to that date, and including wells drilled into pools drilled prior to 1985, among other changes.

On November 19, 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The five-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well's life when production rates are expected to be the highest. Under this program, companies drilling new natural gas or conventional deep oil wells between 1,000 and 3,500 metres receive a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the royalty regime. These options expired on February 15, 2011 and on January 1, 2014, all producers operating under the transitional royalty rates will automatically become subject to the royalty regime. Production from wells operating under the transitional royalty rates will not be subject to the royalty curves for conventional oil and natural gas.

On March 17, 2011, the Government of Alberta approved the New Well Royalty Regulation providing for the permanent implementation of a formerly temporary royalty program which provides for a maximum 5% royalty rate for eligible new wells for the first 12 productive months or until the regulated "volume cap" is reached.

In addition to the foregoing, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the "**Emerging Resource and Technologies Initiative**"). Specifically:

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;
- Shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;
- Horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and
- Horizontal oil wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

The Emerging Resource and Technologies Initiative will be reviewed in 2014, and the Government of Alberta has committed to providing industry with three years notice at that time if it decides to discontinue the program.

Land Tenure

The Alberta provincial government predominantly owns crude oil and natural gas located in Alberta. The provincial government grants rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Private ownership of oil and natural gas also exists in Alberta 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.

The province of Alberta has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license.

Alberta also has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. Leases and licences granted prior to January 1, 2009, but continued after that date, are not subject to shallow rights reversion until they continue past their primary term (at which time the application of deep rights reversion occurs). Afterwards, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009. The order in which these agreements will receive reversion notices will depend on their vintage and location.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time to time. 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, such as sulphur dioxide and nitrous oxide. In addition, such legislation sets out the requirements for the satisfactory abandonment and reclamation of well and facility sites. 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.

On a Federal level and pursuant the Prosperity Act, the Government of Canada amended or appealed several pieces of federal environmental legislation and in addition, created a new federal environment assessment regime. The changes to the environmental legislation under the Prosperity Act are intended to provide for more efficient and timely environmental assessments of projects that previously had been subject to overlapping legislative jurisdiction.

In December 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans.

The Alberta Land Stewardship Act (the "**ALSA**") was proclaimed in force in Alberta on October 1, 2009 and provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA will be deemed to be legislative instruments equivalent to regulations and will be binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, leases, licenses, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment.

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("**LARP**") which came into effect on September 1, 2012. The LARP covers approximately 93,212 square kilometres and is in the northeast corner of Alberta. The region includes a substantial portion of the Athabasca oilsands area, which contains approximately 82% of the provinces oilsands resource and much of the Cold Lake oilsands area. LARP establishes six new conservation areas, bringing the total conserved land in the region to two million hectares, or 22%—an area three times the size of Banff National Park. The Alberta government plans to pay $30 million to producers whose leases will be cancelled in areas set aside for conservation. Oil and gas companies will be allowed to continue to operate in conservation and recreation areas while oilsands companies' tenures will be cancelled. New petroleum and gas tenure sold in conservation areas will include a restriction that prohibits surface access. Application procedures for activities and facilities in the LARP, regulated by the Energy Resources Conservation Board and the Alberta Utilities Commission, respectively, have been changed to accommodate the new restrictions set out in the LARP. The LARP is the first of seven regions to get a land use plan. The next will be the South Saskatchewan region.

Climate Change Regulation

Federal

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both greenhouse gases ("**GHGs**") and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets, which will be applied to regulated sectors on a facility-specific, sector-wide or a company-by-company basis. Facility-specific targets apply to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets. Although the intention was for draft regulations for the implementation of the Updated Action Plan to become binding on January 1, 2010, the only regulations announced pertain to carbon dioxide emissions from coal-fired generation of electricity (finalized in summer 2012). Further, representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. As a result, it is unclear to what extent implementation of the proposals contained in the Updated Action Plan will occur.

The United States Environmental Protection Agency (the "**EPA**") has indicated its intention to impose GHG emissions standards for fossil fuel-fired power plants by specifying that it would issue final regulations by May 26, 2012, and with respect to refineries, specifying that it would issue proposed regulations by December 10, 2011 and finalized regulations by November 10, 2012. The EPA did not meet the December 10, 2011 or November 10, 2012 deadline. Although EPA did not specify a new deadline for issuing the standards, it is expected that these standards will not be issued until after EPA completes proposed GHG performance standards for the power sector. However, in March 2012, the EPA proposed a strict GHG standard on new power plants only. While it is expected that this rule could encourage building new natural gas power plants rather than coal plants, the actual effect of the new rule will not be able to be quantified for some time.

Alberta

Alberta enacted the *Climate Change and Emissions Management Act* (the "**CCEMA**") on December 4, 2003, amending it through the Climate Change and Emissions Management Amendment Act, which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach similar to the Updated Action Plan and aims for a 50% reduction from 1990 emissions relative to GDP by 2020.

Alberta facilities emitting more than 100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. Similar to the Updated Action Plan, the CCEMA and the associated Specified Gas Emitters Regulation make a distinction between "Established Facilities" and "New Facilities". Established Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2000 or that have completed eight or more years of commercial operation. Established Facilities are required to reduce their emissions intensity to 88% of their baseline for 2008 and subsequent years, with their baseline being established by the average of the ratio of the total annual emissions to production for the years 2003 to 2005. New Facilities are defined as facilities that completed their first year of commercial operation on December 31, 2000, or a subsequent year, and have completed less than eight years of commercial operation, or are designated as New Facilities in accordance with the Specified Gas Emitters Regulation. New Facilities are required to reduce their emissions intensity by 2% from baseline in the fourth year of commercial operation, 4% of baseline in the fifth year, 6% of baseline in the sixth year, 8% of baseline in the seventh year, and 10% of baseline in the eighth year. Unlike the Updated Action Plan, the CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA contains compliance mechanisms that are similar to the Updated Action Plan. Regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund at a rate of $15 per tonne of CO2 equivalent. Unlike the Updated Action Plan, CCEMA contains no provisions for an increase to this contribution rate. Emissions credits can be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta.

On December 2, 2010, the Government of Alberta passed the Carbon Capture and Storage Statutes Amendment Act, 2010. It deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision. The risks set out below are not an exhaustive list, nor should be taken as a complete summary or description of all the risks associated with the Corporation's business and the oil and natural gas business generally.

Argentina Risk Factors

Risks of Argentinean Operations

A significant portion of the Corporation's oil and gas properties and operations are located in Argentina where the Corporation is subject to political, economic, and other uncertainties that are specific to entities with Argentinean operations, including, but not limited to, changes in energy policies or the personnel administering them, nationalization, currency fluctuations, exchange controls, and royalty and tax increases. The Corporation's business, financial condition, results of operations, and the value of the Common Shares could also be materially adversely affected by social instability in Argentina and other factors which are not within the control of the Corporation including, among other things, the risks of terrorism, civil strikes, abduction, renegotiation or nullification of existing concessions and contracts, economic sanctions, the imposition of specific drilling obligations, and the development and abandonment of fields. The Corporation's operations may also be adversely affected by laws and policies of Canada affecting foreign trade, taxation and investment. In the event of a dispute arising in connection with the Corporation's operations in Argentina, the Corporation may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdictions of the courts of Canada or enforcing Canadian judgments in such other jurisdictions. The Corporation may also be hindered or prevented from enforcing its rights with respect to a governmental instrumentality because of the doctrine of sovereign immunity. Accordingly, the Corporation's exploration, development and production activities in Argentina could be substantially affected by factors beyond the Corporation's control, any of which could have a material adverse effect on the Corporation's business, financial condition, results of operations, and the value of the Common Shares.

The Government of Argentina announced in 2012 changes to its oil and gas regulatory regime requiring oil, gas and mining exporters to repatriate all of their export revenue. These changes have not had any direct impact on the Corporation as the Corporation does not have existing arrangements or go-forward plans to export production.

The Government of Argentina has recently announced that the Oil Plus programme has been replaced with oil exporters now receiving $70/bbl cash instead of the previous $42/bbl cash price plus an oil credit. Although most (approximately 90%) of the country’s oil production is sold into the domestic market, this move by the Argentina government signifies improvements and simplifications to certain commercial arrangements and is aimed at incentivizing further investment. Madalena currently sells all of its production into the domestic market and receives competitive prices in comparison to this export market. While management of the Corporation does not have any arrangements or current plans to export production, any future changes to the oil and gas pricing mechanisms in Argentina could have a material effect (positive or negative) directly or indirectly on the Corporation.

In November 2012, the Argentinian government also increased wellhead natural gas prices from approximately $5/mmbtu to $7.50/mmbtu for new discoveries or new development projects. This increase is aimed at incentivizing further investment related to gas exploration and development in Argentina, and in particular for unconventional shale gas. In order to qualify for the higher gas prices, operators are required to submit details for any planned development projects along with forecasted volumes for production. As the Corporation’s Argentina gas projects become better defined in the future and move into a development phase, the Corporation may further evaluate the merits of applying for these higher prices.. At this time the Corporation does not have any committed gas volumes under the $7.50/mmbtu pricing arrangement.

In response to declining oil and gas production volumes in Argentina, the federal and various provincial governments in Argentina are calling for oil and gas companies operating in the country to increase investment. In 2012, certain provinces revoked select blocks citing lack of investment, some of which were subsequently given back to the operators later in the year after reaching new agreements on go-forward work plans and commitments. While the Corporation believes that it has met all of its investment commitments to date with respect to its participation in the Coiron Amargo Block, the Cortadera Block and the Curamhuele Block, any future changes to the licencing regime in Neuquén Province, Argentina where the Corporation's acreage is located could have a material adverse effect on the Corporation.

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The Government of Argentina announced in 2012 that it had put forward to Congress a bill seeking to expropriate a controlling 51% interest in the shares of the country's largest oil company, Repsol – YPF. The Corporation is subject to certain political, economic, and other uncertainties related to the nationalization of Repsol-YPF, including, but not limited to, expropriation of property without fair compensation, changes in energy policies or the personnel administering them, a change in oil or natural gas pricing policy, currency fluctuations and devaluations, renegotiation or nullification of existing concessions and contracts, and potential royalty and tax increases. Using the expropriation of YPF as an example, the Corporation's business, financial condition, results of operations, and the value of the Common Shares could be materially adversely affected by actions taken by Congress in Argentina.

The Corporation is currently in discussion with provincial authorities to extend the exploration period of the Cortadera Block beyond the initial expiry period. While the Corporation has agreed on a work program with GyP and is optimistic that formal approval of the extension is forthcoming, a delay or rejection of the extension terms may have a material adverse effect on the Corporation in that the Corporation would be required to relinquish up to 50% of its acreage under the licence.

Economic and Political Developments in Argentina, Including Export Controls

In the past few decades, the Argentinean economy has experienced some periods of extreme volatility including periods of low or negative growth and variable levels of inflation. Inflation peaked in the late 1980's — 90's and in late-2001 there was a severe fiscal crisis, which resulted in restrictions on banking, the imposition of exchange controls, the suspension of payment of Argentina's public debt and the Argentinean Peso ceased to be tied to the U.S. dollar on a one-to-one basis. This further resulted in a year-long period of contractions in economic growth, elevated inflation and a volatile exchange rate.

There is no guarantee of economic stability, which was shown when the Argentinean economy struggled again in 2008. As is the case in many other nations, recently, inflation has been rising and government popularity has decreased, due to the economic situation and the unpopularity of some of the programs the government tried to implement to deal with the global economic crisis. For example, the government applied export controls to agricultural products, which were highly unpopular and caused demonstrations and labour strikes across the country.

The Oil and Gas Industry in Argentina

The crude oil and natural gas industry in Argentina is subject to extensive regulation 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 crude oil and natural gas by agreements among the federal and provincial governments, all of which are subject to change and could have a material impact on the Corporation's business in Argentina. The Federal Government of Argentina has implemented controls for domestic fuel prices and has placed a tax on crude oil and natural gas exports. Any future regulations that limit the amount of oil and gas that the Corporation could sell or any regulations that limit price increases in Argentina and elsewhere could severely limit the amount of the Corporation's revenue and affect its results of operations. In addition, oil and natural gas prices in Argentina are effectively regulated and as a result can be substantially lower than those received in North America.

Fluctuations in Foreign Currency Exchange Rates

Crude oil sales in Argentina are denominated in US dollars but collected in Argentinean Pesos, 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 Corporation's operations.

Effects of Inflation on Results of Operations

Compared to Canada, Argentina has experienced relatively high rates of inflation over the past few years. Since the Corporation is unable to control the market price at which it sells the crude oil it produces, it is possible that significantly higher inflation in the future in Argentina, without a concurrent devaluation of the local currency against the Canadian or US dollar or an increase in the price of crude oil, could have a material adverse effect on the Corporation's results of operations and financial condition.

Foreign Subsidiaries

The Corporation conducts all of its operations in Argentina through foreign subsidiaries. Therefore, to the extent of these holdings, the Corporation will be dependent on the cash flows of these subsidiaries to meet its obligations excluding any additional equity the Corporation may issue from time to time. The ability of its subsidiaries to make payments to the Corporation may be constrained by among other things: the level of taxation, particularly corporate profits and withholding taxes, in the jurisdiction in which it operates; and the introduction of foreign exchange and/or currency controls or repatriation restrictions or the availability of hard currency to be repatriated.

Legal Systems

There can be no assurance that joint ventures, licenses, license applications or other legal arrangements will not be adversely affected by changes in governments, the actions of government authorities or others, or the effectiveness and enforcement of such arrangements.

General Risk Factors

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. Two of the Corporation's three properties in Argentina and approximately 134 net sections of the Corporation's land in Alberta are non-producing oil and gas properties. The risks associated with successfully developing such oil and gas properties are even greater than those associated with successfully continuing development of producing oil and gas properties, since the existence and extent of commercial quantities of oil and gas in unevaluated properties has not been fully established.

The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, the Corporation's existing reserves and the production from them, will decline over time as the Corporation produces from such reserves. A future increase in the Corporation's reserves will depend on both the ability of the Corporation to explore and develop its existing properties and on its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Corporation will be able continue to find satisfactory properties to acquire or participate in. Moreover, management of the Corporation may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participations uneconomic. There is also no assurance that the Corporation will discover or acquire further commercial quantities of petroleum substances.

Future oil and natural gas exploration may involve unprofitable efforts from dry wells as well as from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completing (including hydraulic fracturing), operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents, and 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, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively 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, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, and spills or other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment and personal injury. Particularly, the Corporation 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 Corporation.

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 may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

As is standard industry practice, the Corporation is not fully insured against all risks, nor are all risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event the Corporation could incur significant costs.

Global Financial Markets

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels have caused significant volatility in commodity prices. These events and conditions have caused a decrease in confidence in the broader United States and global credit and financial markets and have created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. While there are signs of economic recovery, these factors have negatively impacted company valuations and are likely to continue to impact the performance of the global economy going forward. Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, actions taken by OPEC and the ongoing global credit and liquidity concerns. This volatility may in the future affect the Corporation's ability to obtain equity or debt financing on acceptable terms.

Prices, Markets and Marketing

Numerous factors beyond the Corporation's control do, and will continue to affect the marketability and price of oil and natural gas acquired or discovered by the Corporation. The Corporation'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. Deliverability uncertainties related to the distance the Corporation's reserves are to pipelines, processing and storage facilities, operational problems affecting pipelines and facilities as well as government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect the Corporation.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions, in the United States, Canada and Europe, the actions of OPEC, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and the Corporation's ability to access such markets. A material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices.

All these factors could result in a material decrease in the Corporation's expected net production revenue and a reduction in its oil and natural gas acquisition, development and exploration activities. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions, and sanctions imposed on certain oil producing nations by other countries and the ongoing credit and liquidity concerns. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural 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.

Market Price of Common Shares

The trading price of securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to the Corporation's performance could include macroeconomic developments nationally, within North America, South America or globally, domestic and global commodity prices or current perceptions of the oil and gas market. Similarly, the market price of the Common Shares could be subject to significant fluctuations in response to variations in the Corporation's operating results, financial condition, liquidity and other internal factors. The price at which the Common Shares will trade cannot be accurately predicted.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation considers acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired businesses may require substantial management effort, time and resources diverting 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 may be periodically disposed of so the Corporation 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 Corporation, if disposed of, may realize less than their carrying value on the financial statements of the Corporation.

Operational Dependence

Other companies operate some of the assets in which the Corporation has an interest. The Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others depends upon a number of factors that may be outside of the Corporation's control, including, but not limited to, 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 Corporation manages 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 Corporation's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Corporation's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling and hydraulic fracturing, or the Corporation's ability to dispose of water used or removed from strata at a reasonable cost and within applicable environmental regulations;
- 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 Corporation could be unable to execute projects on time, on budget, or at all, and may be unable to market the oil and natural gas that it produces effectively.

Gathering and Processing Facilities and Pipeline Systems

The Corporation delivers its products through gathering, processing and pipeline systems some of which it does not own. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering, processing and pipeline systems. The lack of availability of capacity in any of the gathering, processing and pipeline systems, and in particular the processing facilities, could result in the Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation's production. 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 oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Corporation's business and, in turn, the Corporation's financial condition, results of operations and cash flows.

A portion of the Corporation's production may, from time to time, be processed through facilities owned by third parties and over which the Corporation does not have control. From time to time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could materially adversely affect the Corporation's ability to process its production and to deliver the same for sale.

Competition

The petroleum industry is competitive in all its phases. The Corporation competes with numerous other entities in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Corporation's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. The Corporation'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, methods, and reliability of delivery and storage.

Cost of New Technologies

The oil industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other oil companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before the Corporation. There can be no assurance that the Corporation will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. One or more of the technologies currently utilized by the Corporation or implemented in the future may become obsolete. In such case, the Corporation's business, financial condition and results of operations could be materially adversely affected. If the Corporation is unable to utilize the most advanced commercially available technology, its business, financial condition and results of operations could be materially adversely affected.

Alternatives to and Changing Demand for Petroleum Products

Full conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and energy generation devices could reduce the demand for oil and other liquid hydrocarbons. The Corporation cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Corporation's business, financial condition, results of operations and cash flows.

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (exploration, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. See "*Industry Conditions*". The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Corporation's costs, either of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, the Corporation will require licenses from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake. In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, the Corporation's business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada).

Royalty and/or Tax Regimes

There can be no assurance that the federal government and the provincial governments of jurisdictions in which the Corporation operates will not adopt a new or modify the royalty and/or tax regime which may have an impact on the economics of the Corporation's projects. An increase in royalties would reduce the Corporation's earnings and could make future capital investments, or the Corporation's operations, less economic.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate hydrocarbon (oil and natural gas) production. Specifically, hydraulic fracturing is used to produce commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase the Corporation's costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Corporation is ultimately able to produce from its reserves.

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 environmental 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 Corporation to incur costs to remedy such discharge. Although the Corporation 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 have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Climate Change

Argentina 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". There has been much public debate with respect to countries' abilities to meet these targets and the governments' strategy or alternative strategies with respect to climate change and the control of greenhouse gases. The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases and which may require the Corporation to comply with greenhouse gas emissions legislation in Argentina, Alberta or that may be enacted in other provinces. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and as a participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction in greenhouse gas ("**GHG**") emissions from 2005 levels by 2020. These GHG emission reduction targets are not binding, however. Although it is not the case today, some of the Corporation's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. The direct or indirect costs of compliance with these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. 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 Corporation and its operations and financial condition. **[NTD: confirm content.]**

Variations in Foreign Exchange Rates and Interest Rates

World oil and natural gas prices are quoted in U.S. dollars. The Canadian/U.S. dollar exchange rate, which fluctuates over time, consequently affects the price received by Canadian producers of oil and natural gas. Recently, the Canadian dollar has increased materially in value against the U.S. dollar. Material increases in the value of the Canadian dollar negatively affect the Corporation's production revenues. Future Canadian/U.S. exchange rates could accordingly affect the future value of the Corporation's reserves as determined by independent evaluators.

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

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

An increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt, resulting in a reduced amount available to fund its exploration and development activities, and if applicable, the cash available for dividends and could negatively impact the market price of the Common Shares.

Substantial Capital Requirements

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, the Corporation's ability to do so is dependent on, among other factors:

- the overall state of the capital markets;
- the Corporation's credit rating (if applicable);
- interest rates;
- royalty rates;
- tax burden due to current and future tax laws; and
- investor appetite for investments in the energy industry and the Corporation's securities in particular.

Further, if the Corporation'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 Corporation. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

Additional Funding Requirements

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and from time to time, the Corporation may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. There is risk that if the economy and banking industry experienced unexpected and/or prolonged deterioration, the Corporation's access to additional financing may be affected.

Because of the global economic volatility, the Corporation may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited, unavailable, or available on onerous terms, the Corporation's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of the Corporation's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production on the Corporation's properties.

Credit Facility Arrangements

The Corporation currently has a credit facility and the amount authorized thereunder is dependent on the borrowing base determined by its lenders. The Corporation is required to comply with covenants under its credit facility which may, in certain cases, include certain financial ratio tests, which from time to time either affect the availability, or price, of additional funding and in the event that the Corporation does not comply with these covenants, the Corporation's access to capital could be restricted or repayment could be required. Events beyond the Corporation's control may contribute to the failure of the Corporation to comply with such covenants. A failure to comply with covenants could result in the default under the Corporation's credit facility, which could result in the Corporation being required to repay amounts owing thereunder. Even if the Corporation is able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to the Corporation. If the Corporation is unable to repay amounts owing under credit facilities, the lenders under the credit facility could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. The acceleration of the Corporation's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Corporation's credit facility may impose operating and financial restrictions on the Corporation that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to the Corporation's securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

The Corporation's lenders use the Corporation's reserves, commodity prices, applicable discount rate and other factors, to periodically determine the Corporation's borrowing base. A material decline in commodity prices could reduce the Corporation's borrowing base, reducing the funds available to the Corporation under the credit facility which could result in the requirement to repay a portion, or all, of the Corporation's bank indebtedness.

Issuance of Debt

From time to time, the Corporation may enter into transactions to acquire assets or shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase the Corporation's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Corporation may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time, could impair the Corporation'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 Corporation 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, to the extent that the Corporation engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Corporation's hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes;
- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement;
- the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil and natural gas prices.

Similarly, from time to time the Corporation 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 Corporation 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 Corporation and may delay exploration and development activities.

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 Corporation's claim. The actual interest of the Corporation in properties may, therefore, vary from the Corporation's records. If a title defect does exist, it is possible that the Corporation may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. There may be valid challenges to title or proposed legislative changes which affect title, to the oil and natural gas properties the Corporation controls that, if successful or made into law, could impair the Corporation's activities on them and result in a reduction of the revenue received by the Corporation.

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 in this document are estimates only. Generally, 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 natural gas;
- royalty rates; and
- the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

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 Corporation'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.

The estimation 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. Such variations could be material.

In accordance with applicable securities laws, the Corporation'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 Corporation's oil and natural 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 Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom and 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, except as may be specifically stated, has not been updated and thus does not reflect changes in the Corporation's reserves since that date.

Insurance

The Corporation's involvement in the exploration for and development of oil and natural gas properties may result in the Corporation becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Corporation 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, certain risks are not, in all circumstances, insurable or, in certain circumstances, the Corporation 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 Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Geopolitical Risks

Political events throughout the world that cause disruptions in the supply of oil continue to affect the marketability and price of oil and natural gas acquired or discovered by the Corporation. Conflicts, or conversely peaceful developments, arising outside of Canada have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and result in a reduction of the Corporation's net production revenue.

In addition, the Corporation's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of the Corporation's properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have insurance to protect against the risk from terrorism.

Dilution

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

Management of Growth

The Corporation may be subject to growth related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Corporation 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 Corporation to deal with this growth may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Expiration of Licences and Leases

The Corporation's properties are held in the form of licences and leases and working interests in licences and leases. If the Corporation 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 Corporation's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

The following is a summary of the status the Corporation’s three blocks in Argentina:

Coiron Amargo Block

In March 2012 an application by the Coiron Amargo joint venture to convert the northern 108 km^2 of the 404 km^2 block to a 25 year exploitation concession (Coiron Amargo Norte) was approved by the Province of Neuquén. In addition, the exploration period for the remainder of the block (Coiron Amargo Sur) was extended to November 8, 2013. Madalena’s remaining share of future development commitments associated with Coiron Amargo Norte to December 31, 2013 is approximately $4.1 million plus VAT.

The extension of Coiron Amargo Sur to November 8, 2013 required additional work commitments of US$ 33.5 million (Madalena share – US$ 13.0 million of which approximately US$ 4.9 million plus VAT remains outstanding). The exploration block (Coiron Amargo Sur) qualifies for an additional one year extension period at the end of the exploration period in the fourth quarter of 2013.

Cortadera Block

The initial exploration period for the Cortadera Block in the Province of Neuquén had an initial expiry of October 26, 2011. A new proposal was made by the joint venture to formalize an extension of the initial exploration period based on a proposed work plan for the block. As of December 31, 2012, the original proposal was yet to be finalized and discussions between the Province of Neuquen and the joint venture were recently reopened resulting in the decision to submit a new proposal. During the first quarter of 2013, the joint venture submitted a revised proposal and is currently working towards approval of an agreed upon work program for the block.

Curamhuele Block

In March 2012 the exploration period for the block was extended to November 8, 2013. The extension of the block required additional work commitments of US$ 17.6 million (Madalena share – US$ 17.6 million of which approximately US $14.1 million plus VAT remains outstanding). The exploration block qualifies for an additional one year extension after November 13, 2013. In December 2012, Madalena initiated the process to qualify the Curamhuele block for an additional one year extension. Throughout the first quarter of 2013, the Company has made steady progress with respect to this application and is currently in the advanced stages of the approval process.

Dividends

The Corporation 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 Corporation, the need for funds to finance ongoing operations and other considerations, as the Board of Directors of the Corporation considers relevant.

Litigation

In the normal course of the Corporation's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, related to personal injuries, property damage, property tax, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Corporation and as a result, could have a material adverse effect on the Corporation's assets, liabilities, business, financial condition and results of operations.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of Alberta. The Corporation is not aware that any claims have been made in respect of its properties and assets; however, if a claim arose and was successful such claim may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, the Corporation may disclose confidential information relating to the business, operations or affairs of this Corporation. Although confidentiality agreements are signed by third parties prior to the disclosure of any confidential information, a breach could put the Corporation at competitive risk and may cause significant damage to its business. The harm to the Corporation's business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, the Corporation will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to its business that such a breach of confidentiality may cause.

Income Taxes

The Corporation files all required income tax returns and believes that it is in full compliance with the provisions of the *Income Tax Act* (Canada) and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Corporation, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

A tax treaty exists between Argentina and Canada. Oil companies are subject to a generally applicable corporate tax regime. All successful exploration and field development costs, including intangible costs may be depreciated on a unit-of-production basis. Tax payers pay either income tax at a rate of 35 percent on corporate net profits or a minimum tax, based on net assets, whichever is the greater. Minimum tax was reinstated effective January 1999 and is levied on cumulative capital less accumulated depreciation plus an inflation adjustment at a rate of one percent. In April 1992, the tax base for locally incorporated companies was changed from Argentine source income to worldwide income.

Madalena is unaware of any prevailing currency restrictions with respect to repatriating after tax income from Argentina.

Income tax laws relating to the oil and natural gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects the Corporation. Furthermore, tax authorities having jurisdiction over the Corporation may disagree with how the Corporation calculates its income for tax purposes or could change administrative practices to the Corporation's detriment.

Seasonality

The level of activity in the Canadian oil and natural 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 natural 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 Corporation as the demand for natural gas rises during cold winter months and hot summer months.

Third Party Credit Risk

The Corporation 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 Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may affect a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

Conflicts of Interest

Certain directors or officers of the Corporation may also be directors or officers of other oil and natural gas companies and as such may, in certain circumstances, have a conflict of interest. Conflicts of interest, if any, will be subject to and governed by procedures prescribed by the ABCA which require a director of officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the Corporation disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA. See "*Directors and Officers – Conflicts of Interest*".

Reliance on Key Personnel

The Corporation's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

The contributions of the existing management team to the immediate and near term operations of the Corporation 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 Corporation 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 Corporation.

Initial Well Rates Are Not Determinative of Future or Continuing Production Rates

Any references in this Annual Information Form to test rates, flow rates, initial and/or final raw test or production rates, early production and/or "flush" production rates are useful in confirming the presence of hydrocarbons, however, such rates are not necessarily indicative of long-term performance or of ultimate recovery. Such rates may also include recovered "load" fluids used in well completion stimulation. Readers are cautioned not to place reliance on such rates in calculating the aggregate production for the Corporation. In addition, the Vaca Muerta shale is an unconventional resource play, which may be subject to high initial decline rates.

Expansion into New Activities

The operations and expertise of the Corporation's management are currently focused primarily on oil and gas production, exploration and development in Alberta and Argentina in the areas discussed in this Annual Information Form. In the future the Corporation may acquire or move into new industry related activities or new geographical areas, may acquire different energy related assets, and as a result may face unexpected risks or alternatively, significantly increase the Corporation's exposure to one or more existing risk factors, which may in turn result in the Corporation's future operational and financial conditions being adversely affected.

Forward-Looking Information May Prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on the Corporation's forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risk and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Additional information on the risks, assumption and uncertainties are found under the heading "*Reader Advisory Regarding Forward-Looking Statements*" of this Annual Information Form.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors and senior officers of the Corporation, 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 Corporation's last completed financial year or in any proposed transaction which has materially affected or will materially affect the Corporation except as described herein.

MATERIAL CONTRACTS

Except for contracts entered into by the Corporation in the ordinary course of business or otherwise disclosed herein, the Corporation 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 NI 51-102 by the Corporation during, or related to, the Corporation's most recently completed financial year other than Ryder Scott and McDaniel, the Corporation's independent engineering evaluators and KPMG LLP, the Corporation's auditors.

To the knowledge of the Corporation, Ryder Scott and McDaniel, or principals thereof, did not have any registered or beneficial interests, direct or indirect, in any securities or other property of the Corporation or of the Corporation'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 Corporation 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 Corporation or its associates or affiliates.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies is, or is expected to be elected, appointed or employed as a director, officer or employee of the Corporation or of any associate or affiliate of the Corporation, except Jay Reid, a director of the Corporation who is a partner at Burnet, Duckworth & Palmer LLP, which law firm renders legal services to the Corporation.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans, is contained in the Corporation's Information Circular for the most recent annual meeting of shareholders that involved the election of directors. Additional financial information is provided in the Corporation'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 Corporation, may be found on SEDAR at www.sedar.com.

SCHEDULE A – RYDER SCOTT

FORM 51-101F2
Report on Reserves Data
By Independent Qualified Reserves Evaluator or Auditor

To the Board of Directors of Madalena Ventures Inc. (the "**Corporation**"):

1. We have evaluated the Corporation's reserves data as at December 31, 2012. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2012, estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Corporation'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 presented 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 Corporation evaluated by us for the year ended December 31, 2011, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Corporation'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, Thousand US Dollars)**			
			Audited	**Evaluated**	**Reviewed**	**Total**
Ryder Scott Petroleum Consultants Ltd.	Madalena Ventures Inc. Coiron Amargo Block as at December 31, 2012 and prepared April 26, 2013	Argentina	Nil	10,887	Nil	10,887
TOTAL			**Nil**	**10,887**	**Nil**	**10,887**

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, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.
7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Ryder Scott Petroleum Consultants Ltd.
Calgary, Alberta

Execution Date: April 26, 2013

(signed) *"Herman G. Acuna"*

Herman G. Acuna, P.E.
TBPE License No. 92254
Managing Senior Vice President - International

SCHEDULE B MCDANIEL

FORM 51-101F2
Report on Reserves Data
By Independent Qualified Reserves Evaluator or Auditor

To the Board of Directors of Madalena Ventures Inc. (the "**Corporation**"):

1. We have evaluated the Corporation's reserves data as at December 31, 2012. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2012, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Corporation'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 presented 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 Corporation evaluated by us for the year ended December 31, 2011, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Corporation'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, Thousand CDN Dollars)**			
			Audited	**Evaluated**	**Reviewed**	**Total**
McDaniel		Canada	Nil	22,893	Nil	22,893
TOTAL			**Nil**	**22,893**	**Nil**	**22,893**

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, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

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

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

Executed as to our report referred to above:

McDaniel Petroleum Consultants Ltd.
Calgary, Alberta

Execution Date: April 26, 2013

(signed) *"P.A. Welch"*
P. A. Welch, P.Eng.
President & Managing Director

SCHEDULE "C"

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

Management of Madalena Ventures Inc. (the "**Corporation**") are responsible for the preparation and disclosure of information with respect to the Corporation'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, 2012, estimated using forecast prices and costs.

Independent qualified reserves evaluators have evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluators will be filed with the securities regulatory authorities concurrently with this report.

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

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

The Reserves Committee of the board of directors has reviewed the Corporation'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 reports of the independent qualified reserves evaluators 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.

Dated at Calgary, Alberta, this 26 day of April, 2013.

(signed) *"Kevin Shaw"*	(signed) *"Ving Y. Woo"*
Kevin Shaw, President & Chief Executive Officer and Director	Ving Y. Woo Director and Chairman of the Reserves Committee
(signed) *"Thomas Love"*	(signed) *"Keith Mcadonald"*
Thomas Love Vice-President Finance & Chief Financial Officer	Keith Macdonald Director