Annual Information Form

Year Ended December 31, 2013

April 28, 2014

TABLE OF CONTENTS

DEFINITIONS

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

"**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 28, 2014;

"**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 MASA;

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

"**Corporation**" or "**Madalena**" means Madalena Energy Inc.;

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

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

"**CSA 51 324**" means Staff Notice 51 324 – *Glossary to NI 51 101 Standards of Disclosure for Oil and Gas Activities* of the Canadian Securities Administrators.

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

"**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;

"**IFRS**" means International Financial Reporting Standards;

"**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 28, 2014 evaluating the Canadian crude oil, natural gas liquids and natural gas reserves of the Corporation as at December 31, 2013.;

"**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;

"**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.;

"**Rights Plan**" means the Shareholder Rights Plan of the Corporation adopted April 24, 2012;

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

"**Ryder Scott Report**" means the report of Ryder Scott dated April 15, 2014 evaluating the Argentinean crude oil, natural gas liquids and natural gas reserves of the Corporation as at December 31, 2013;

"**SEDAR**" means the System for Electronic Document Analysis and Retrieval at www.sedar.com;

"**Shareholders**" means the 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.

ADDITIONAL INFORMATION WITH RESPECT TO OIL & GAS DISCLOSURE

Definitions

Certain terms used in this Annual Information Form in describing reserves and other oil and natural gas information are defined below. Certain other terms and abbreviations used in this Annual Information Form, but not defined or described, are defined in NI 51-101, CSA 51-324 or the COGE Handbook and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101, CSA 51-324 or the COGE Handbook.

Reserves

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: (a) analysis of drilling, geological, geophysical and engineering data; (b) the use of established technology; and (c) specified economic conditions, which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates as follows:

"**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.

"**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.

The qualitative certainty levels referred to in the definitions above are applicable to "individual reserves 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 reserves estimates are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and
- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

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

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

"**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.

"**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.

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

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to sub-divide 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.

Interests in Reserves, Production, Wells and Properties

"**gross**" means: (a) in relation to Madalena's interest in production or reserves, Madalena's "company gross reserves", which are Madalena's working interest (operating or non-operating) share before deduction of royalties and without including any of Madalena's royalty interests; (b) in relation to wells, the total number of wells in which Madalena has an interest; and (c) in relation to properties, the total area of properties in which Madalena has an interest.

"**net**" means: (a) in relation to Madalena's interest in production or reserves Madalena's working interest (operating or non-operating) share after deduction of royalty obligations, plus Madalena's royalty interests in production or reserves; (b) in relation to Madalena's interest in wells, the number of wells obtained by aggregating Madalena's working interest in each of Madalena's gross wells; and (c) in relation to Madalena's interest in a property, the total area in which Madalena has an interest multiplied by Madalena's working interest.

"**working interest**" means the percentage of undivided interest held by Madalena in the oil and/or natural gas or mineral lease granted by the mineral owner, Crown or freehold, which interest gives Madalena the right to "work" the property (lease) to explore for, develop, produce and market the leased substances.

Description of Exploration and Development Wells and Costs

"**development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the crude oil and natural gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to: (a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves; (b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly; (c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and (d) provide improved recovery systems.

"**development well**" means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

"**exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and natural gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "**prospecting costs**") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are: (a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as "**geological and geophysical cost**s"); (b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records; (c) dry hole contributions and bottom hole contributions; (d) costs of drilling and equipping exploratory wells; and (e) costs of drilling exploratory type stratigraphic test wells.

"**exploration well**" means a well that is not a development well, a service well or a stratigraphic test well.

"**service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

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

CAUTION RESPECTING RESERVES INFORMATION

The determination of oil and natural gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved and probable reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery. The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

The recovery and reserve estimates of oil, NGLs and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein. The estimated future net revenue from the production of Madalena's natural gas and petroleum reserves does not represent the fair market value of Madalena's reserves.

CAUTION RESPECTING BOE

In this Annual Information Form, the abbreviation BOE means barrel of oil equivalent on the basis of 1 Bbl to 6 Mcf of natural gas when converting natural gas to BOEs. **BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf to 1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given 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 Mcf to 1 Bbl, utilizing a conversion ratio at 6 Mcf: 1 Bbl 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, the anticipated timing of expenditures by Madalena to satisfy Madalena's asset retirement obligations, the anticipated impact of environmental laws and regulations on Madalena, Madalena's plans for the development of Madalena's proved and probable undeveloped reserves, Madalena's anticipated land expiries, Madalena's plans for funding future development costs, Madalena's expectations as the means of funding Madalena's ongoing environmental obligations, Madalena's tax horizon, Madalena's corporate strategy, Madalena's planned capital expenditures and drilling activity in 2014 and the anticipated impact of the factors discussed under the heading "*Industry Conditions*" on Madalena 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 SEDAR and Madalena's website (www.madalenaenergy.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-IFRS MEASURES

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS, such as netbacks, and therefore are considered non-IFRS measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in order to provide readers with additional measures for analyzing Madalena's ability to generate funds to finance operations and information regarding liquidity. The additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS.

ANALOGOUS INFORMATION

Certain information in this document may constitute "analogous information" as defined in NI 51-101, 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.

CORPORATE STRUCTURE

General

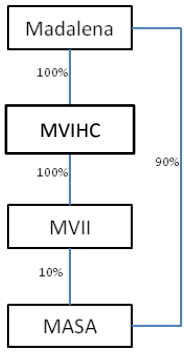
Madalena was created under the laws of the Province of British Columbia on September 14, 2001 pursuant to the Arrangement. On September 30, 2004 Madalena amalgamated with its wholly-owned subsidiary, RMS Medical Systems Research (B.C.) Ltd. On August 22, 2006, the Corporation completed the 2006 Arrangement. 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. On July 30, 2013, the Shareholders approved the change in the Corporation's name to Madalena Energy Inc. and articles of amendment were filed.

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

The Corporation's principal office is located at 200, 707 - 7th Avenue S.W., Calgary, Alberta, T2P 3H6, and the Corporation's registered office is located at Suite 2400, 525 - 8th Avenue S.W., Calgary, Alberta, T2P 1G1.

Inter-corporate Relationships

The Corporation owns 100% of the outstanding common shares of MVIHC, which in turn owns 100% of the outstanding common shares of MVII. Both of these entities are incorporated under the laws of Barbados. Madalena also owns 90% of the outstanding common shares of MASA, an entity existing under the laws of Argentina, and MVII owns the remaining 10% of the outstanding common shares of MASA. Madalena carries on all of its exploration and development activities in Argentina through MASA. The corporate structure diagram is as follows:



GENERAL DEVELOPMENT OF THE BUSINESS

Madalena is an independent, Canadian-based, international and domestic upstream oil and gas company whose main business activities include exploration, development and production of crude oil, natural gas liquids and natural gas. Internationally, Madalena holds three blocks within the Neuquén basin in Argentina comprised of approximately 132,200 net acres on the Coiron Amargo Block (approximately 34,950 net acres), the Curamhuele Block (approximately 50,600 net acres) and the Cortadera Block (approximately 46,650 net acres). Domestically, Madalena's core area of operations is located in the greater Paddle River area of west-central Alberta, where the Corporation holds approximately 200 gross (155 net) sections of land (78% average working interest).

The following is a summary of the business operations of the Corporation over the last three completed financial years.

Year 2011

Cortadera Block Farmout and License Amendments

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.

Year 2012

March, 2012 Short Form Offering

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.

Shareholder Rights Plan

On April 24, 2012, the Corporation adopted 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.

Online Acquisition

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.

Management Changes

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 of the Corporation.

On November 27, 2012, the Corporation announced a full cycle operating team including Mr. Steve Dabner as Vice President, Exploration, Mr. Brent Foster as Vice President, Engineering and Mr. Rob Stanton as Vice President, Operations.

Year 2013

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

Financial Advisor Retained

In June 2013, to accelerate exploration and development activities in Argentina, the Company continues to assess opportunities with RBC Capital Markets ("RBC"), Madalena's exclusive advisor related to its Neuquen basin assets, in respect of a possible joint venture partnership or other transaction.

Credit Facilities
On June 11, 2013, the Corporation increased to its credit facilities with the National Bank of Canada. The revolving operating demand loan and the acquisition / development demand loan was increased from $4.75 million to $10.0 million and from $1.25 million to $3.0 million, respectively.

July, 2013 Private Placements
On July 11, 2013, the Corporation closed two private placement financings for aggregate gross proceeds of approximately $7.25 million through the issuance of:

(a) 11,765,000 Common Shares issued as CEE "flow-through shares" within the meaning of the *Income Tax Act* (Canada) at a price of $0.34 per share for gross proceeds of $4.00 million by way of "bought deal" private placement; and

(b) (i) 200,000 Common Shares at a price of $0.31 per share; (ii) 4,780,000 Common Shares issued as CDE "flow-through shares" within the meaning of the *Income Tax Act* (Canada) at a price of $0.32 per share; and (iii) 4,886,765 Common Shares issued as CEE "flow-through shares" within the meaning of the *Income Tax Act* (Canada) at a price of $0.34 per share for gross proceeds of $3.25 million by way of brokered private placement.

November, 2013 Private Placement
On November 21, 2013, Madalena closed a private placement offering of CDE "flow through shares" for gross proceeds of $3.0 million.

December, 2013 Short Form Offering
On December 5, 2013 Madalena closed a bought deal short form prospectus offering issuing an aggregate of 19,575,300 Common Shares at an issue price of $0.47 per Common Share, including 2,553,300 Common Shares issued pursuant to the exercise of the over-allotment option, for aggregate gross proceeds of $9.2 million.

2014 Recent Developments
On February 11, 2014, Madalena closed a bought deal short form prospectus offering issuing an aggregate of 32,857,225 Common Shares at an issue price of $0.70 per Common Share, including 4,285,725 Common Shares issued pursuant to the exercise of the over-allotment option, for aggregate gross proceeds of $23.0 million.

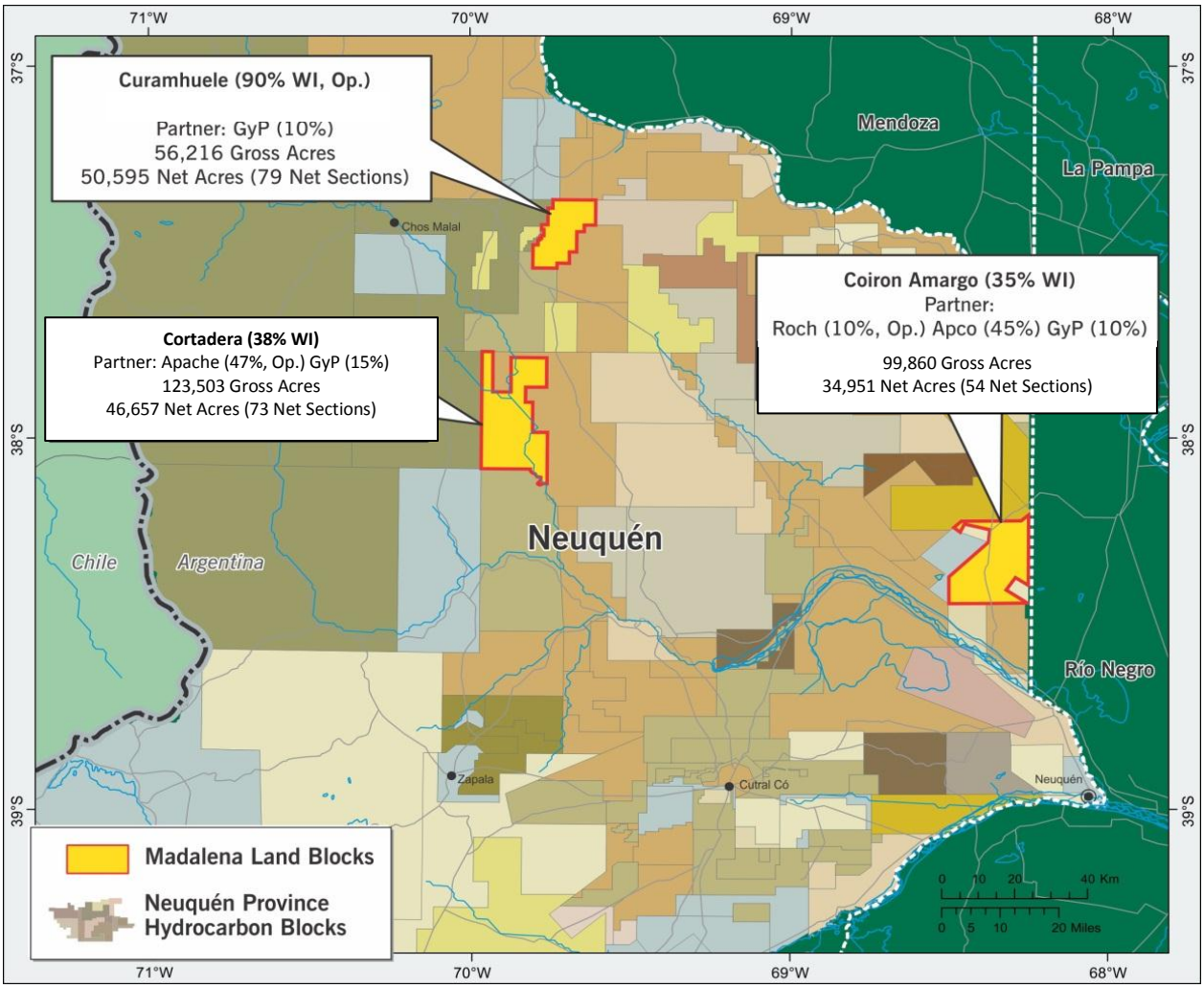
Significant Acquisitions
During the year ended December 31, 2013, Madalena did not complete any "significant acquisitions" within the meaning of that term in National Instrument 51-102 – *Continuous Disclosure Obligations*.

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 greater 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, high impact exploration, conventional reserves, and unconventional shale resources.

Argentinean Operations



Source: Based on mapping by the Gobierno de la Provincia del Neuquén, modified by Madalena Energy Inc.

The Corporation's international operations are comprised of exploration opportunities in the Neuquén basin of Argentina, including significant exposure to unconventional shale and tight sand resources. The portfolio consists of three 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.

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.

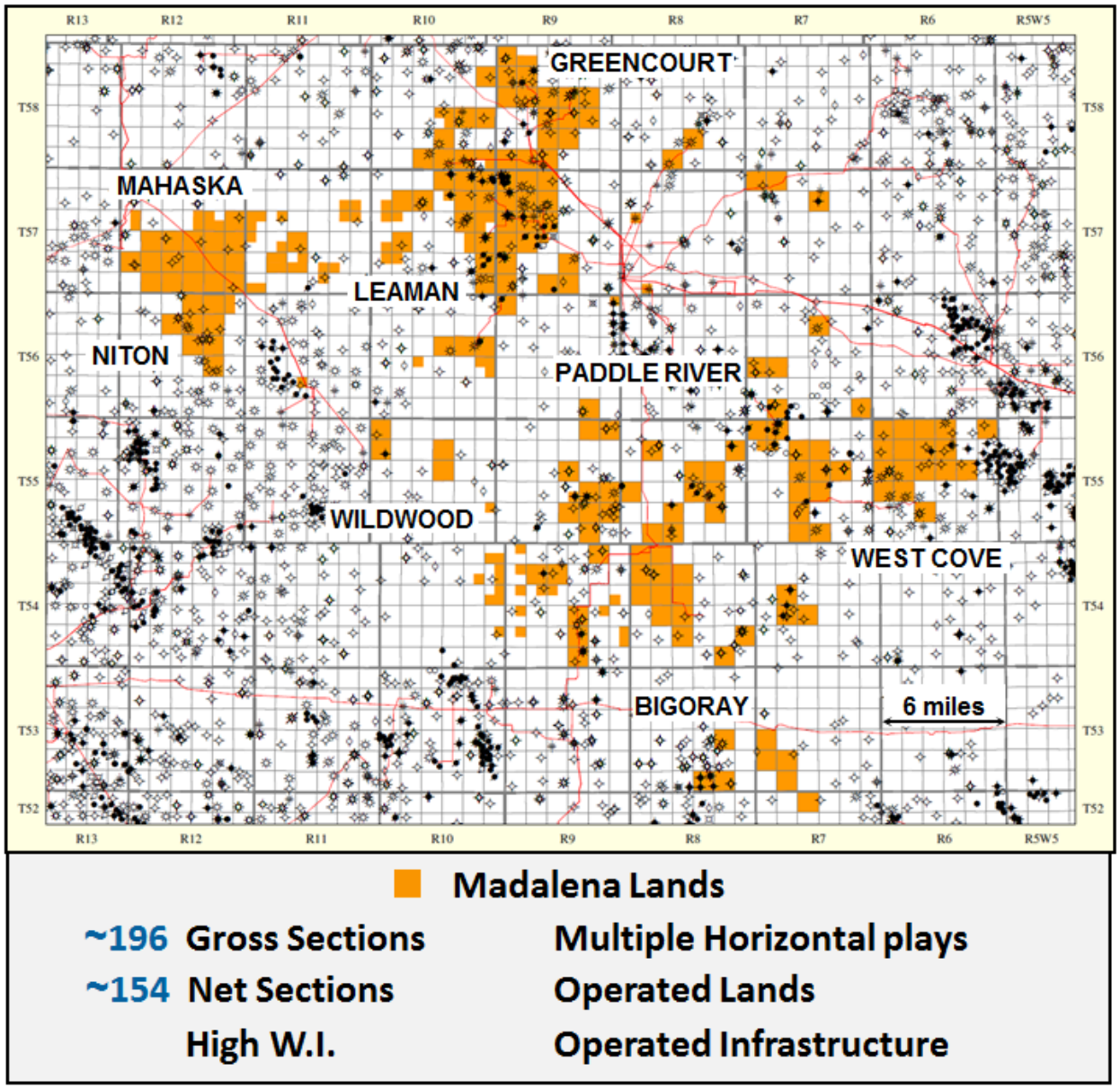
The Neuquén basin is a roughly triangular shaped back-arc basin of approximately 137,000 square kilometres, located on the eastern front of the Andes mountains in central-western Argentina. The basin stretches from the town of Malargue in the north over a distance of 650 kilometres to the south and has 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 279,580 gross acres of exploration area.

As part of its corporate strategy, Madalena operates in the region through strategic alliances with local exploration and development companies and is an operator of record in the country through its Argentina subsidiary MASA.

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*".

Canadian Operations



Madalena Lands

~196	Gross Sections	Multiple Horizontal plays
~154	Net Sections	Operated Lands
	High W.I.	Operated Infrastructure

Madalena's core area of operations is located in the Greater Paddle River area of west-central Alberta where the Corporation holds approximately 196 gross (approximately 154 net) sections of land (approximately 78% average W.I.) encompassing light oil and liquids-rich gas resource plays. Madalena's primary domestic focus is to exploit its large inventory of horizontal drilling locations on its Ostracod oil and emerging oil & liquids-rich gas resource plays.

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

Competitive Conditions

There is considerable competition, in both Argentina and Canada, 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, access to capital markets or strategic financial partnerships 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 National Energy Board (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 treated at the Corporation's recently built oil treatment plant and delivered directly to local refineries. 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 "*Other Oil and Gas Information – Principal Properties – Argentina"*.

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 2013, 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 and 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 seven full-time employees in Canada and three 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.

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 is set forth below (the "**Statement**") is dated April 15, 2014 for the Ryder Scott Report and April 28, 2014 for the McDaniel Report. The effective date of the statement is December 31, 2013 and the preparation date of the statement is April 15, 2014 for the Ryder Scott Report and April 28, 2014 for the McDaniel Report. 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, 2013. 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, 2013. 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 Reports on Reserves Data by our independent qualified reserves evaluators in Form 51-101F2 are attached as Schedule "A" and Schedule "B". The Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 are attached as Schedule "C".

The Reserve Reports are 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, 2013 include a full year of operating data on the properties of the Corporation. As at December 31, 2013, all of the Corporation's reserves are located in Argentina and Canada.

All evaluations of future revenue are stated after royalties, development costs, production costs and well abandonment costs but before consideration of the deduction of future income tax expenses (unless otherwise noted in the tables), 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, 2013 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, 2013 Bank of Canada noon spot exchange rate of 1 US $ = $1.0636 CDN for the tables indicating total reserves of the Corporation.

Summary of Oil and Gas Reserves
and Net Present Values of Future Net Revenue
at December 31, 2013

Forecast Prices and Costs

ARGENTINA	Reserves									
	Light/Medium Crude Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		Oil Equivalent	
	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)
Proved										
Developed Producing	183.4	161.4	-	-	264.2	232.5	-	-	227.4	200.2
Developed Non-Producing	20.0	17.6	-	-	9.2	8.1	-	-	21.5	19.0
Undeveloped	382.9	336.9	-	-	458.8	403.7	-	-	459.4	404.2
Total Proved	586.2	515.9	-	-	732.2	644.3	-	-	708.2	623.3
Probable	408.1	359.1	-	-	436.2	383.9	-	-	480.8	423.1
Total Proved Plus Probable	994.3	875.0	-	-	1168.4	1028.2	-	-	1189.0	1046.4

CANADA	Reserves									
	Light/Medium Crude Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		Oil Equivalent	
	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)
Proved										
Developed Producing	295.4	249.9	35.4	35.6	5302.3	4650.4	300.3	218	1514.8	1278.5
Developed Non-Producing	74.8	63.3	-	-	261.6	229.1	14.4	11.1	132.7	112.6
Undeveloped	-	-	-	-	1735.4	1310.0	43.4	29.6	332.6	247.9
Total Proved	370.2	313.1	35.4	35.6	7299.3	6189.5	358.1	258.7	1980.1	1639
Probable	391.9	323.3	9.5	9.7	5183.5	4294.5	213.5	151.0	1478.9	1199.8
Total Proved Plus Probable	762.1	636.5	45.0	45.4	12482.8	10484.0	571.6	409.7	3459.0	2838.8

TOTAL	Reserves									
	Light/Medium Crude Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		Oil Equivalent	
	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)
Proved										
Developed Producing	478.8	411.3	35.4	35.6	5566.5	4882.9	300.3	218.0	1742.2	1478.7
Developed Non-Producing	94.8	80.9	-	-	270.8	237.2	14.4	11.1	154.2	131.6
Undeveloped	382.9	336.9	-	-	2194.2	1713.7	43.4	29.6	792.0	652.1
Total Proved	956.4	829.0	35.4	35.6	8031.5	6833.8	358.1	258.7	2688.3	2262.3
Probable	800.0	682.4	9.5	9.7	5619.7	4678.4	213.5	151.0	1959.7	1622.9
Total Proved Plus Probable	1756.4	1511.5	45.0	45.4	13651.2	11512.2	571.6	409.7	4648.0	3885.2

ARGENTINA	Net Present Values of Future Net Revenue										
	Before Income Taxes Discounted at (%/year)					After Income Taxes Discounted at (%/year) [3]					$/BOE Unit Value Before tax Discounted at
Reserves Category US$	0% MM	5% MM	10% MM	15% MM	20% MM	0% MM	5% MM	10% MM	15% MM	20% MM	10%
Proved											
Developed Producing	6.891	6.462	6.069	5.713	5.390	5.822	5.453	5.116	4.810	4.534	26.69
Developed Non-Producing	0.527	0.4649	0.409	0.366	0.3147	0.482	0.424	0.371	0.324	0.282	18.99
Undeveloped	4.729	3.571	2.569	1.702	0.950	4.123	3.016	2.060	1.235	0.521	5.59
Total Proved	12.147	10.497	9.047	7.773	6.654	10.427	8.892	7.546	6.369	5.337	12.77
Probable	19.161	16.385	14.120	12.261	10.724	14.788	12.350	10.387	8.799	7.508	29.37
Total Proved Plus Probable	31.307	26.882	23.168	20.034	17.377	25.215	21.241	17.933	15.168	12.845	19.48

CANADA	Net Present Values of Future Net Revenue										
	Before Income Taxes Discounted at (%/year)					After Income Taxes Discounted at (%/year) [3]					$/BOE Unit Value Before tax Discounted at
Reserves Category CDN$	0% MM	5% MM	10% MM	15% MM	20% MM	0% MM	5% MM	10% MM	15% MM	20% MM	10%
Proved											
Developed Producing	21.262	17.968	15.671	13.993	12.717	21.262	17.968	15.671	13.993	12.717	10.33
Developed Non-Producing	0.804	0.479	0.218	0.008	-0.165	0.804	0.479	0.218	0.008	-0.165	1.65
Undeveloped	2.703	1.232	0.428	-0.037	-0.316	2.703	1.232	0.428	-0.037	-0.316	1.29
Total Proved	24.768	19.679	16.317	13.964	12.236	24.768	19.679	16.317	13.964	12.236	8.23
Probable	21.101	13.581	9.262	6.568	4.774	21.101	13.581	9.262	6.568	4.774	6.26
Total Proved Plus Probable	45.869	33.259	25.579	20.532	17.010	45.869	33.259	25.579	20.532	17.010	7.39

TOTAL	Net Present Values of Future Net Revenue										
	Before Income Taxes Discounted at (%/year)					After Income Taxes Discounted at (%/year) [3]					$/BOE Unit Value Before tax Discounted at
Reserves Category CDN$	0% MM	5% MM	10% MM	15% MM	20% MM	0% MM	5% MM	10% MM	15% MM	20% MM	10%
Proved											
Developed Producing	28.591	24.840	22.127	20.069	18.449	27.454	23.767	21.112	19.109	17.540	12.679
Developed Non-Producing	1.364	0.973	0.653	0.397	0.170	1.317	0.930	0.613	0.352	0.135	4.234
Undeveloped	7.733	5.030	3.160	1.773	0.694	7.088	4.439	2.619	1.276	0.238	3.990
Total Proved	37.687	30.844	25.939	22.232	19.313	35.858	29.136	24.343	20.738	17.913	9.639
Probable	41.480	31.008	24.280	19.609	16.180	36.830	26.716	20.310	15.927	12.759	12.390
Total Proved Plus Probable	79.167	61.851	50.220	41.840	35.493	72.688	55.851	44.653	36.665	30.672	10.805

Total Future Net Revenue
(Undiscounted)
at December 31, 2013

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	52.665	7.900	17.789	14.174	0.655	12.147	1.720	10.427
Total Proved Plus Probable Reserves	90.261	13.539	28.264	16.369	0.781	31.307	6.092	25.215

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	96.498	14.134	49.729	6.728	1.139	24.768	0	24.768
Total Proved Plus Probable Reserves	178.402	27.785	84.567	18.767	1.414	45.869	0	45.869

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	152.512	22.536	68.650	21.803	1.836	37.687	1.829	35.858
Total Proved Plus Probable Reserves	274.403	42.185	114.629	36.177	2.244	79.167	6.480	72.688

Future Net Revenue by Production Group
at December 31, 2013

Argentina US$	Production Group	Future Net Revenue Before Income Taxes Discounted at 10% MM – US$	Unit Value[4] Before Income Taxes Discounted at 10% $/bbl, $/Mcf
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	9.047	17.54
	Heavy oil (including solution gas and other by-products)	-	-
	Natural gas (including by-products but excluding solution gas from oil wells)	-	-
Proved plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	23.168	26.48
	Heavy oil (including solution gas and other by-products)	-	-
	Natural gas (including by-products but excluding solution gas from oil wells)	-	-

Canada CDN$	Production Group	Future Net Revenue Before Income Taxes Discounted at 10% MM – CDN$	Unit Value[4] Before Income Taxes Discounted at 10% $/bbl, $/Mcf
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	12.226	39.04
	Heavy oil (including solution gas and other by-products)	0.559	19.28
	Natural gas (including by-products but excluding solution gas from oil wells)	3.532	0.89
Proved plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	18.897	29.69
	Heavy oil (including solution gas and other by-products)	0.692	18.74
	Natural gas (including by-products but excluding solution gas from oil wells)	5.99	0.92

Total CDN$	Production Group	Future Net Revenue Before Income Taxes Discounted at 10% MM – CDN$	Unit Value[4] Before Income Taxes Discounted at 10% $/bbl, $/Mcf
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	21.849	26.35
	Heavy oil (including solution gas and other by-products)	0.559	19.28
	Natural gas (including by-products but excluding solution gas from oil wells)	3.532	0.89
Proved plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	43.538	28.80
	Heavy oil (including solution gas and other by-products)	0.692	18.74
	Natural gas (including by-products but excluding solution gas from oil wells)	5.990	0.92

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, 2013. 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.
(4) Unit values are calculated using the 10% discount rate divided by the major product type net reserves for each group

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, 2013 in the Ryder Scott Report in estimating reserves data using forecast prices and costs.

Summary of Pricing and Inflation Rate Assumptions
at December 31, 2013

Forecast Prices and Costs

	Argentina Domestic	
Year	**Oil Price 40°API $US/bbl**	**Gas Price $US/ MMbtu**
2014	81.59	4.22
2015	83.22	4.31
2016	84.89	4.39
2017	86.58	4.48
2018	88.32	4.57
2019	90.08	4.66
2020	91.88	4.76
2021	93.72	4.85
2022	95.60	4.95
2023	97.51	5.05
2024	99.46	5.15
2025	101.45	5.25
2026	103.48	5.36
2027	105.55	5.46
2028	107.66	5.57

Notes:

(1) Escalation at 2% per year after 2028.
(2) All costs escalate at 2% per year from 2014.
(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, 2013 from its Argentina oil and gas properties was CDN$81.17/bbl for crude oil and CDN$4.48 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 well-sites 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, 2013 in the McDaniel Report in estimating reserves data using forecast prices and costs.

	Medium and Light Crude Oil			Natural Gas		
Year	**WTI Cushing Oklahoma 40° API[1] (US$/bbl)**	**Edmonton Par Price 40° API[2] ($/bbl)**	**Cromer Medium 29.3° API[3] ($/bbl)**	**Alberta Gas Average Plant gate ($/MMBtu)**	**AECO - C Spot ($/MMBtu)**	**Exchange Rate ($US/$CDN)**
2014	95.00	95.00	89.30	3.80	4.00	0.95
2015	95.00	96.50	90.70	4.05	4.25	0.95
2016	95.00	97.50	91.70	4.35	4.55	0.95
2017	95.00	98.00	92.10	4.55	4.75	0.95
2018	95.30	98.30	92.40	4.80	5.00	0.95
2019	96.60	99.60	93.60	5.05	5.25	0.95
2020	98.50	101.60	95.50	5.10	5.35	0.95

	Medium and Light Crude Oil			Natural Gas		
Year	WTI Cushing Oklahoma 40° API[1] (US$/bbl)	Edmonton Par Price 40° API[2] ($/bbl)	Cromer Medium 29.3° API[3] ($/bbl)	Alberta Gas Average Plant gate ($/MMBtu)	AECO - C Spot ($/MMBtu)	Exchange Rate ($US/$CDN)
2021	100.50	103.60	97.40	5.20	5.45	0.95
2022	102.50	105.70	99.40	5.30	5.55	0.95
2023	104.60	107.90	101.40	5.40	5.65	0.95
2024	106.70	110.00	103.40	5.50	5.75	0.95
2025	108.80	112.20	105.50	5.65	5.90	0.95
2026[4]	111.00	114.50	•107.60	5.75	6.00	0.95

	Natural Gas Liquids		
Year	Edmonton Cond. & Natural Gasolines ($/bbl)	Edmonton Propane ($/bbl)	Edmonton Butane ($/bbl)
2014	102.50	50.20	76.60
2015	101.60	50.50	77.80
2016	100.60	50.60	78.60
2017	101.20	51.30	79.00
2018	101.50	52.00	79.20
2019	102.90	53.20	80.30
2020	105.00	54.10	81.90
2021	107.00	55.20	83.50
2022	109.20	56.30	85.20
2023	111.50	57.40	87.00
2024	113.70	58.50	88.60
2025	115.90	59.80	90.40
2026[4]	118.30	61.00	92.30

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) Escalated at 2%/yr. thereafter

The weighted average realized sales prices before hedging for the year ended December 31, 2013 were $3.12/Mcf for natural gas, $78.26/Bbl for light and medium crude oil, $81.81/Bbl for heavy oil and $57.00/Bbl for NGLs. The price received for medium crude oil was lower than the price received for heavy crude as a result of flush production from a medium crude oil well during the months of November and December (November and December oil production represented 36% of 2013 oil production) when the average price received from oil sales averaged $66.89/bbl compared to $82.45/bbl for the first 10 months of 2013.

Reconciliation of Changes in Reserves

The following tables set out the reconciliation of the Corporation's gross reserves as at December 31, 2013 compared to December 31, 2012 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)**	**Proved (MMcf)**	**Probable (MMcf)**	**Proved Plus Probable (MMcf)**
December 31, 2012	391.1	253.6	644.8	323.7	212.8	536.5
Extensions	382.9	317.3	700.2	458.8	324.8	783.6
Improved Recovery						
Technical Revisions	-121.4	-162.8	-284.2	12.0	-101.4	-89.4
Discoveries						
Acquisitions						
Dispositions						
Economic Factors						
Production	-66.4		-66.4	-62.3		-62.3
December 31, 2013	586.2	408.1	994.4	732.2	436.2	1168.4

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, 2012	283.0	249.3	532.3	45.0	5.4	50.4
Extensions	74.7	258.9	333.6	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions	15.5	-150.0	-134.5	-0.6	4.2	3.6
Discoveries	-	-	-	-	-	-
Acquisitions	68.8	33.7	102.5	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	-71.8		-71.8	-9.0		-9.0
December 31, 2013	370.2	391.9	762.1	35.4	9.6	45.0

	Natural Gas Liquids			Natural Gas		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2012	391.8	182.7	574.5	7538.1	4477.1	12015.2
Extensions	14.4	49.9	64.3	261.6	906.2	1167.8
Improved Recovery	-	-	-	-	-	-
Technical Revisions	-4.3	-22.4	-26.7	563.1	-258.7	304.4
Discoveries	-	-	-	-	-	-
Acquisitions	6.1	3.3	9.4	111.5	58.9	170.4
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	-49.9	-	-49.9	-1175.0	-	-1175.0
December 31, 2013	358.1	213.5	571.6	7299.3	5183.5	12482.8

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, 2012	674.1	502.9	1177.1	45	5.4	50.4
Extensions	457.6	576.2	1033.8	0	0	0
Improved Recovery	0	0	0	0	0	0
Technical Revisions	-105.9	-312.8	-418.7	-0.6	4.2	3.6
Discoveries	0	0	0	0	0	0
Acquisitions	68.8	33.7	102.5	0	0	0
Dispositions	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0
Production	-138.2	0	-138.2	-9	0	-9
December 31, 2013	956.4	800	1756.5	35.4	9.6	45

	Natural Gas Liquids			Natural Gas		
	Total Proved (Mbbl)	Total Probable (Mbbl)	Total Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2012	391.8	182.7	574.5	7861.8	4689.9	12551.7
Extensions	14.4	49.9	64.3	720.4	1231	1951.4
Improved Recovery	0	0	0	0	0	0
Technical Revisions	-4.3	-22.4	-26.7	575.1	-360.1	215
Discoveries	0	0	0	0	0	0
Acquisitions	6.1	3.3	9.4	111.5	58.9	170.4
Dispositions	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0
Production	-49.9	0	-49.9	-1237.3	0	-1237.3
December 31, 2013	358.1	213.5	571.6	8031.5	5619.7	13651.2

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by McDaniel and Ryder Scott in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are generally those reserves related to infill wells that have not yet been drilled or wells further away from gathering systems requiring relatively high capital to bring on production. Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. This also includes the probable undeveloped wedge from the proved undeveloped locations.

The Corporation currently plan to pursue the development of its proved and probable undeveloped reserves within the next two years through ordinary course capital expenditures. In some cases, it will take longer than two years to develop these reserves. There are a number of factors that could result in delayed or cancelled development, including the following: (i) existence of higher priority expenditures; (ii) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (iii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iv) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (v) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (vi) surface access issues (including those relating to land owners, weather conditions and regulatory approvals).

Proved undeveloped reserves have been assigned in areas where the reserves can be estimated with a high degree of certainty. In most instances, proved undeveloped reserves will be assigned on lands immediately offsetting existing producing wells within the same accumulation or pool.

Probable undeveloped reserves have been assigned in areas where the reserves can be estimated with less certainty. It is equally likely that that the actual remaining quantities recovered will be greater or less than the proved plus probable reserves. In most instances probable undeveloped reserves have been assigned on lands in the area with existing producing wells but there is some uncertainty as to whether they are directly analogous to the producing accumulation or pool.

For more information, see "*Risk Factors*".

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, 2013, 2012 and 2011 and, in the aggregate, before that time based on forecast prices and costs.

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

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	477.4	477.4	549.7	549.7
2011	123.2	351.1	265.7	570.3
2012	-	-	-	-
2013	313.9	336.9	365.0	403.7

Ryder Scott has assigned 404.2 Mboe of proved undeveloped net reserves in the Ryder Scott Report with $14.6 million Cdn of associated undiscounted capital, of which $14.6 million Cdn is forecast to be spent in the first two years.

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	497.4	497.4	397.1	397.1
2011	92.4	320.3	213.5	438.5
2012	81.8	126.9	78.6	121.8
2013	173.5	231.0	190.0	273.5

Ryder Scott has assigned 276.6 Mboe of probable net undeveloped reserves in the Ryder Scott Report with $14.6 million CDN of associated undiscounted capital, of which $14.6 million CDN is forecast to be spent in the first two years.

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	-	-	-	-	-	-
2011	-	-	-	-	-	-
2012	85.1	85.1	1571.1	1571.1	48.1	48.1
2013	-	-	-	1310.0	-	-

McDaniel has assigned 247.9Mboe of proved undeveloped net reserves in the McDaniel Report with $3.9 million CDN of associated undiscounted capital, of which $3.9 million CDN is forecast to be spent in the first two years.

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	-	-	-	-	-	-
2011	-	-	-	-	-	-
2012	138.9	138.9	2336.6	2336.6	65.7	65.7
2013	192.7	192.7	752.3	2601.2	35.1	71.0

McDaniel has assigned 697.2 Mboe of probable undeveloped net reserves in the McDaniel Report with $16.0 million CDN of associated undiscounted capital, of which $12.0 million CDN is forecast to be spent in the first two years.

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	477.4	477.4	549.7	549.7	-	-
2011	123.2	351.1	265.7	570.3	-	-
2012	85.1	205.5	1571.1	1686.7	48.1	48.1
2013	313.9	336.9	365	1713.7	-	-

Ryder Scott and McDaniel have collectively assigned 652.1 Mboe of proved undeveloped net reserves in the Ryder Scott Report and the McDaniel Report with $18.5 million CDN of associated undiscounted capital, of which $18.5 million CDN is forecast to be spent in the first two years.

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	497.4	497.4	397.1	397.1	-	-
2011	92.4	320.3	213.5	438.5	-	-
2012	220.7	265.8	2415.2	2458.4	65.7	65.7
2013	366.2	423.7	942.3	2874.7	35.1	71.0

Ryder Scott and McDaniel have collectively assigned 973.8 Mboe of probable undeveloped net reserves in the Ryder Scott Report and the McDaniel Report with $30.6 million CDN of associated undiscounted capital, of which $26.6 million CDN is forecast to be spent in the first two years.

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**
2014	9.586	11.782
2015	4.588	4.588
2016	-	-
2017	-	-
2018	-	-
Total (Undiscounted)	14.174	16.369
Total (Discounted at 10%)	13.376	15.483

CANADA

CDN$	Forecast Prices and Costs (MM)	
Year	**Proved Reserves**	**Proved Plus Probable Reserves**
2014	2.781	7.168
2015	3.947	7.625
2016	-	3.973
2017	-	-
2018	-	-
Total (Undiscounted)	6.728	18.767
Total (Discounted at 10%)	6.039	16.678

TOTAL

CDN$	Forecast Prices and Costs (MM)	
Year	**Proved Reserves**	**Proved Plus Probable Reserves**
2014	12.977	19.699
2015	8.827	12.505
2016	-	-
2017	-	-
2018	-	-
Total (Undiscounted)	21.803	36.177
Total (Discounted at 10%)	20.266	33.146

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

Principal Properties

The following is a description of Madalena's principal oil and natural gas properties as at December 31, 2013. Unless otherwise indicated, production stated is average daily production for the year ended December 31, 2013 received by the Corporation in respect of its working interest share before deduction of royalties and without including any royalty interest.

ARGENTINA

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 in the Argentine province of Neuquén. The Coiron Amargo block (35% W.I.) held by Madalena is divided into two regions called Coiron Amargo Norte (northern portion of the block) and Coiron Amargo Sur (southern portion of the block).

In March 2012, an application by the Coiron Amargo joint venture to convert Coiron Amargo Norte (108 km^2 of the 404 km^2 block) to a 25 year exploitation (development) concession was approved by the Province of Neuquén.

Coiron Amargo Sur is currently under an exploration contract which was extended until November 8, 2014 by way of an official decree signed by the Province of Neuquén in Argentina on October 22, 2013. Post November 8, 2014, Madalena has the ability to extend Coiron Amargo Sur through further exploration, evaluation and/or exploitation (development) phases. The remaining work commitments in Coiron Amargo Sur are estimated at approximately USD$ 2.35 million plus VAT (net to Madalena) as of December 31, 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.

Activity during 2013 included drilling three (1.05 net) wells, the shooting of two 3D seismic programs at Coiron Amargo Sur, the construction of three surface facility components at Coiron Amargo Norte and the spudding of a fourth well at CAS.x-15 targeting the Vaca Muerta. The CAS X-5 vertical exploration well was drilled and cased, encountering approximately 325 feet (100 meters) of Vaca Muerta shale on logs with an average total organic content of over 4% and an average of 7% porosity in the lower Vaca Muerta. The CAS.x-14 vertical exploration well was drilled and cased encountering approximately 105 meters of Vaca Muerta shale on logs. The CAN.xr-2(h) well was re-entered and drilled horizontally in the Sierras Blancas light oil reservoir. This well

represents the first horizontal well drilled into the Sierras Blancas conventional light oil reservoir on the Coiron Amargo block. This horizontal well was subsequently cased, completed and a multi-rate production test was carried out through temporary production facilities. Throughout the multi-rate production test, the CAN.xr-2(h) well flowed without artificial lift equipment and was tested for approximately 142 hours at various choke settings ranging from 4 mm to 12 mm in size. During the test period, the total produced cumulative volumes were approximately 2,736 gross (958 net) barrels of oil (38 degree API) and approximately 4,154 gross (1,454 net) mscf of natural gas, for a total of approximately 3,428 gross (1,200 net) barrels of oil equivalent (80% oil). No significant flowing pressure declines were observed throughout any of the test rates and no water was produced throughout the test period. The well was produced through a single well battery, trucking the oil to the central plant and flaring the solution gas, from late December 2013 to mid-March, 2014. On March 19, 2014, the well was tied into a pipeline to the central plant and gas dehydration and compressor facility.

Production in 2013 was from seven Sierras Blancas oil wells at Coiron Amargo Norte. Average production for 2013, net to the Corporation, was 170 bopd and 126 mcf/d, resulting in 191 boe/d.

The Ryder Scott Report attributes proved reserves of 0.7 MMBOE and proved plus probable reserves of 1.2 MMBOE to Madalena's working interests in the Coiron Amargo Block.

Madalena has established a 2014 capital budget of $48 million, $37 million of which is allocated to Argentina. As part of the 2014 budget, activity on the Coiron Amargo block is focused on a combination of high impact horizontal drilling and completions work in the Sierras Blancas light oil play (including the current CAN–15(h) location and two additional horizontals), along with unconventional Vaca Muerta shale delineation work (including planned completions / fracture stimulations on the CAS.x-15 and CAS.x.14 vertical wells and new Vaca Muerta shale drilling in 2014).

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. 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 of 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 deep exploration well (along with testing key zones of interest satisfactory to Madalena) 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% with additional carried work on an uphole zone(s) of interest to be conducted in 2014 in order to fulfill the testing requirement of this deep test.

On January 15, 2014, the Corporation announced that, on the Cortadera Block, the joint venture partnership consisting of Apache Corporation, Gas y Petroleo del Neuquén SA and Madalena signed an amended contract agreement to formalize a multi-year agreement for the extension of the initial exploration period and inclusion of subsequent exploration periods. Subsequent to that agreement and following an application and approval process, the first exploration period for Cortadera was extended by way of an official decree which was signed by the Province of Neuquén in Argentina. This extension provides the partnership until October 26, 2014 to satisfy the remaining work commitments on the block, which involves the upcoming re-entry work.

Under the amended agreement, and subsequent to conducting the upcoming re-entry work, the partnership at Cortadera has the option to enter into subsequent exploration periods involving a second exploration period extending to October 25, 2018 and a third exploration upon which the partnership has the option to enter into subsequent exploration periods involving a second exploration period extending to October 25, 2021, or extend the Cortadera Block through potential further evaluation and/or exploitation phases.

The decree signed by the Province of Neuquén, as noted above, stipulates that Gas y Petroleo del Neuquén SA, which is the provincial petroleum company within the Province of Neuquén and is a working interest partner in the Cortadera Block, upwardly revised its carried working interest in the block to 15% from the previous 10%, resulting in a proportionate reduction of Madalena's working interest in the block to 37.8% compared to its previous 40% working interest.

Madalena and its new incoming partner (YPF S.A. post the purchase of the Apache subsidiary in Argentina) plan to re-enter the previously drilled CorS.x-1 Vaca Muerta test well to evaluate an up-hole zone of interest in the wellbore targeting the Mulichinco

tight sand play. Madalena believes that its share of any work performed is not expected to be significant due to Apache's obligation to pay for the majority of the costs of the anticipated work program.

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 thrust 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 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 of the equivalent of US$2.0 million which included the drilling of at least one well. 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 block qualified for an additional one year extension after November 13, 2013. In June 2013, the exploration period was extended until November 8, 2014 by way of an official decree signed by the Province of Neuquén in Argentina. The remaining work commitments at Curamhuele are approximately US $13.8 million plus VAT. After satisfying these remaining work commitments, Madalena expects to either convert certain area(s) of the acreage into an exploitation (development) concession and/or enter into a new exploration period(s) or unconventional evaluation phase, to further explore and appraise the Curamhuele block.

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.

The key zones of interest across the Curamhuele block are the unconventional Vaca Muerta shale, Lower Agrio shale and liquids rich Mulichinco, as well as other conventional formations of interest. To accelerate exploration and development activities in Argentina, the Company continues to assess different opportunities with RBC Capital Markets ("RBC"), Madalena's exclusive advisor related to its Neuquen basin assets, in respect of a possible joint venture partnership or other transaction.

Madalena continues to assess opportunities with RBC, the Corporation's Neuquén basin financial advisor to accelerate operational activities across the block and to unlock value in the unconventional shales, tight sand plays and conventional zones of interest.

To satisfy the remaining commitments on the block in 2014, planned activity for the year includes the shooting of a 3D seismic program covering approximately 75 square kilometers and the execution of two high impact re-entries of the Yp.x-1001 and Ch.x-1 wellbores to test an estimated 200 meter thick tight sand play in the liquids-rich Mulichinco and an estimated 225 meter thick oil zone in the Lower Agrio shale (which is a second emerging unconventional shale play in Argentina), respectively prior to November 2014. In additional, given area offset activity by major E&P companies, Madalena is also evaluating the Vaca Muerta shale as a key zone of interest across the block.

CANADA

Greater Paddle River Area

On November 1, 2012, pursuant to the acquisition of all of the issued and outstanding shares of Online, the Corporation established operations in Canada and entered the domestic E&P sector. Madalena's core area of operations is located in the greater Paddle River area of west-central Alberta, where the Corporation holds approximately 196 gross (approximately 154 net) sections of land (approximately 78% average working interest).

Since the Corporation established operations in Canada on November 1, 2012, a total of 8 (7.92 wells have been drilled, 7 (6.92 net) of which have been horizontal wells), resulting in 4 (4 net) oil wells, one (1.0 net) gas well, 1 (0.92 net) well currently being further evaluated and 2 (2 net) abandoned wells.

The Corporation has working interests in 99 gross (69.7 net) wells, of which 13 (9.4 net) are oil, 22 (15.5 net) are gas and 64 (44.8 net) are non-producing. Production for the year ended December 31, 2013 averaged 222 bbls/d of oil, 3,223 mcf/d of gas and 137

bbls/d of liquids. Production from the Corporation's Ostracod oil project accounted for 453 boe/d (51%) of total Canadian production of 896 boe/d in 2013.

The Corporation's reserve life index in Canada (RLI) is 9.5 years based on Proved plus Probable reserves of approximately 3.5MMBOE and total volume of production per day estimated by McDaniel for 2014 in the McDaniel Report.

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, 2013:

	Oil Wells		Natural Gas Wells		Non-producing Wells		Total	
Location	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Argentina	9	3.5	-	-	7	4.0	16	7.5
Canada	13	9.4	22	15.5	64	44.8	99	69.4
Total	22	12.9	22	15.5	71	48.8	115	76.9

Properties With No Attributed Reserves

The following table sets forth Madalena's undeveloped land position as at December 31, 2013:

	Gross		Net	
Location	**Acres**	**Sections**	**Acres**	**Sections**
Argentina, South America	252,873	395	122,855	192
Alberta, Canada	97,453	152	86,415	135

In Canada, Madalena expects 5,920 gross (5,237 net) acres to expire in 2014.

The remaining work commitments relating to the Corporation’s concessions in Argentina are described under Principal Properties – Argentina.

Existing infrastructure on the Coiron Amargo block will enable the Corporation to bring successful wells on-stream relatively quickly in 2014 and in future years. At Curamhuele, there is nearby infrastructure including processing facilities and pipeline networks and development of production and net operating income from a successful drilling program at Curamhuele could be realized after building tie-in facilities to already existing offset infrastructure. At this stage, the Cortadera Block does not have established facilities or pipelines on the block and the development of a successful drilling program may be delayed pending the development of suitable infrastructure in this area.

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, 2014 to Oct. 31, 2014	300 GJ/d	$4.52CDN	$4.52 CDN	AECO
Natural gas fixed	April 1, 2014 to Oct. 31, 2014	300 GJ/d	$4.43CDN	$4.43 CDN	AECO
Natural gas fixed	April 1, 2014 to Oct. 31, 2014	500 GJ/d	$3.45CDN	$3.45 CDN	AECO
Natural gas fixed	April 1, 2014 to Oct. 31, 2014	300 GJ/d	$3.55CDN	$3.55 CDN	AECO
Crude oil call options	Jan. 1, 2014 to Dec. 31, 2014	50 bbl/d	-	$100.00 US	WTI
Crude oil call options	Jan. 1, 2014 to Dec. 31, 2014	50 bbl/d	-	$100.00 US	WTI
Crude oil swap	Feb 1, 2014 to Dec. 31, 2014	50 bbl/d	-	$100.00 CDN	WTI
Crude oil call options	Jan. 1, 2015 to Dec. 31, 2015	50 bbl/d	-	$95.00 US	WTI

Additional Information Concerning Abandonment Costs

Madalena estimates well abandonment costs on an area-by-area basis using historical costs supplemented by current industry costs and changes in regulatory requirements. Estimated costs of abandonment and reclamation were included in the Ryder Scott Report. Estimated costs of abandonment were included in the McDaniel Report and applied 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 McDaniel Report. In addition, the financial statements include abandonment and reclamation obligations for wells that were not assigned year-end reserves, neither of which are included in the Reserves Reports.

The following tables set forth the abandonment and reclamation costs in respect of proved plus probable reserves using forecast prices for Argentina. The Corporation has 16 gross (7.5 net) wells for which it expects to incur abandonment and reclamation costs.

Argentina ($CDN)	**Proved Plus Probable Abandonment and Reclamation Costs Undiscounted SMM**	**Proved Plus Probable Abandonment and Reclamation Costs Discounted at 10% $MM**
Abandonment and reclamation costs associated with wells that have assigned reserves (1)	0.9	0.4
Abandonment and reclamation costs associated with non-producing, shut-in and wells that have no assigned reserves (1)	1.2	0.5
Total abandonment and reclamation costs provision	2.1	0.9
Portion forecast to be paid during the next three years	Nil	Nil

Note:

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

The following tables set forth the abandonment and reclamation costs in respect of proved plus probable reserves using forecast prices for Canada. The Corporation has 99 gross (69.7 net) wells for which it expects to incur abandonment costs.

Canada ($CDN)	**Proved Plus Probable Abandonment and Reclamation Costs Undiscounted SMM**	**Proved Plus Probable Abandonment and Reclamation Costs Discounted at 10% $MM**
Abandonment costs associated with wells that have assigned reserves (1)	1.6	0.5
Reclamation costs associated with wells that have assigned reserves (1)	1.3	0.2
Abandonment and reclamation costs associated with non-producing, shut-in and wells that have no assigned reserves (1)	3.6	1.3
Total abandonment and reclamation costs provision	6.6	2.0
Portion forecast to be paid during the next three years	nil	nil

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, 2013:

	Argentina $CDN - MM	**Canada $CDN - MM**	**Total $CDN - MM**
Exploration costs	9.3	11.2	20.5
Development costs	5.7	17.1	22.8
Total	15.0	28.3	43.3

Exploration and Development Activities

The following table sets forth, by country, the gross and net exploratory and development wells in which the Corporation participated during the year ended December 31, 2013:

CANADA

	Exploratory Wells		**Development Wells**	
	Gross	**Net**	**Gross**	**Net**
Light and Medium Oil	1.00	1.00	3.00	3.00
Heavy Oil	-	-	-	-
Natural Gas	-	-	-	-
Dry	1.00	1.00	-	-
Service/Other (1)	1.00	0.92	-	-
Stratigraphic Test	-	-	-	-
Total	**3.00**	**2.92**	**3.00**	**3.00**

(1) Included in Service/Other is a horizontal well drilled in Q4-2013 in West Cove targeting the Ostracod oil formation in which the Corporation has a 92% working interest. The Corporation has yet to complete its evaluation of this well.

ARGENTINA

	Exploratory Wells		Development Wells	
	Gross	**Net**	**Gross**	**Net**
Light and Medium Oil	2.00	0.70	1.00	0.35
Heavy Oil	-	-	-	-
Natural Gas	-	-		-
Dry	-	-	-	-
Service/Other	-	-	-	-
Stratigraphic Test	-	-	-	-
Total	**2.00**	**0.70**	**1.00**	**0.35**

Production Estimates

The following table sets out the volume of the Corporation's gross working interest production estimated for the year ended December 31, 2014 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** *(Bopd)*	**Natural Gas** *(Mcf/d)*	**Natural Gas Liquids** *(Bbls/d)*	**BOE** *(Boe/d)*
Total Proved					
Argentina	494	-	654	-	603
Canada	251	18	2,713	131	852
	745	18	3,367	131	1,455
Total Probable					
Argentina	179	-	201	-	213
Canada	76	-	342	19	152
	255	-	543	19	365
Total Proved Plus Probable					
Argentina	673	-	855	-	816
Canada	327	18	3,055	150	1004
	1,000	18	3,910	150	1,820

Production History

Madalena's daily production, before royalties, on a quarterly basis and for the year ended December 31, 2013 is summarized below:

ARGENTINA

Production

	Q4 2013	**Q3 2013**	**Q2 2013**	**Q1 2013**
Light and medium oil – Bbls/d	154	171	178	177
Heavy oil – Bbls/d	-	-	-	-
Natural gas – Mcf/d	117	106	146	134
Natural gas liquids – Bbls/d	-	-	-	-
Total production – BOE/d	173	189	203	199

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 2013	Q3 2013	Q2 2013	Q1 2013
Prices Received	79.53	77.00	69.90	75.06
Royalties Paid	(10.11)	(11.87)	(12.19)	(11.69)
Production Costs	(40.14)	(42.36)	(40.43)	(38.35)
Netback	29.28	22.77	17.28	25.02

Prices Received

The following table discloses, on a quarterly basis and for the year ended December 31, 2013, the prices received by product type.

	Q4 2013	Q3 2013	Q2 2013	Q1 2013
Light and medium crude oil - $/Bbl	86.05	81.92	75.87	81.48
Natural gas - $/Mcf	4.66	4.94	4.36	4.07

CANADA

Production

	Q4 2013	Q3 2013	Q2 2013	Q1 2013
Light and medium oil – Bbls/d	380	211	93	125
Heavy oil – Bbls/d	17	18	26	15
Natural gas – Mcf/d	3,249	3,732	3,356	2,541
Natural gas liquids – Bbls/d	160	137	140	110
Total production – BOE/d	1,098	988	819	674

The majority of the Canadian wells produce 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 2013	Q3 2013	Q2 2013	Q1 2013
Prices Received	45.57	44.73	39.46	42.21
Royalties Paid	(5.34)	(8.19)	(5.66)	(8.09)
Production Costs	(18.43)	(18.56)	(21.61)	(17.76)
Netback	21.80	17.98	12.19	16.36

Netbacks – natural gas

$ per Mcfe	Q4 2013	Q3 2013	Q2 2013	Q1 2013
Prices Received	5.77	4.66	5.15	5.39
Royalties Paid	(0.60)	(0.24)	(0.18)	(0.34)
Production Costs	(6.86)	(3.53)	(2.74)	(3.67)
Netback	(1.70)	0.89	2.24	1.38

CANADA	Q4 2013	Q3 2013	Q2 2013	Q1 2013
Light and medium crude oil - $/Bbl	68.75	95.19	83.01	74.98
Heavy oil - $/Bbl	72.68	94.84	83.37	73.30
Natural gas - $/Mcf	3.48	2.36	3.53	3.25
NGLs - $/Bbl	54.39	54.54	47.68	58.03

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, 2013 for each product type.

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	203	19	3,223	137	896	82
Argentina	170	-	126	-	191	18
Total	351	41	3,349	137	1,087	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 April 28, 2014, there were 396,885,731 Common Shares issued and outstanding. In addition, as at such date, there were an aggregate of 19,529,999 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 exchange under the symbol "MVN" and on the OTC exchange under the symbol “MDLNF”.

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, 2013:

Period	High ($)	Low ($)	Volume
2013			
January	0.41	0.29	17,132,775
February	0.45	0.36	17,585,908
March	0.42	0.33	8,100,214
April	0.38	0.24	24,874,244
May	0.48	0.29	45,851,352
June	0.39	0.26	20,199,848
July	0.38	0.27	13,958,524
August	0.42	0.34	13,252,014
September	0.50	0.36	29,994,439
October	0.60	0.45	28,391,955
November	0.57	0.45	25,818,010
December	0.73	0.48	42,758,480

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, 2013:

Date	Securities	Number of Securities	Price per Security
February 8, 2013	Common Shares upon exercise of stock options	83,700	$0.105
February 8, 2013	Common Shares upon exercise of stock options	500,000	$0.21
March 4, 2013	Issuance of stock options(1)	1,260,000	$0.405(2)
March 4, 2013	Common Shares upon exercise of stock options	200,000	$0.105
March 4, 2013	Common Shares upon exercise of stock options	750,000	$0.21
March 5, 2013	Common Shares upon exercise of stock options	100,000	$0.21
March 19, 2013	Common Shares upon exercise of stock options	150,000	$0.21
May 13, 2013	Common Shares upon exercise of stock options	250,000	$0.21
May 28, 2013	Common Shares upon exercise of stock options	500,000	$0.21
July 11, 2013	Common Shares(3)	200,000	$0.31
July 11, 2013	CDE flow-through Common Shares(3)	4,780,000	$0.32
July 11, 2013	CEE flow-through Common Shares(3)	16,651,765	$0.34
August 1, 2013	Common Shares upon exercise of stock options	50,000	$0.21
August 27, 2013	Issuance of stock options(1)	6,000,000	$0.35(2)
September 19, 2013	Common Shares upon exercise of stock options	25,000	$0.105
September 19, 2013	Common Shares upon exercise of stock options	150,000	$0.21
October 19, 2013	Common Shares upon exercise of stock options	200,000	$0.42
November 21, 2013	CDE Flow-Through Shares issued pursuant to the Private Placement(4)	5,555,556	$0.54
December 5, 2013	Common Shares issued pursuant to the December Offering	19,575,300	$0.47

Notes:

(1) As of the date hereof, 19,529,999 options issued pursuant to the Corporation's stock option plan were outstanding at exercise prices between $0.105 and $0.96.

(2) Reflects the exercise price of such Options.

(3) On July 11, 2013, Madalena issued the following securities pursuant to certain private placement financings: (a) 200,000 Common Shares at a price of $0.31 per share; (b) 4,780,000 Common Shares issued as "Canadian development expense flow-through shares" within the meaning of the Tax Act at a price of $0.32 per share; and (c) 16,651,765 Common Shares issued as "Canadian exploration expense flow-through shares" within the meaning of the Tax Act at a price of $0.34 per share.

(4) On November 21, 2013, Madalena issued 5,555,556 Common Shares issued as "Canadian development expense flow-through shares" within the meaning of the Tax Act at a price of $0.54 per share.

(5) On February 11, 2014, Madalena closed a bought deal short form prospectus offering issuing an aggregate of 32,857,225 Common Shares at an issue price of $0.70 per Common Share, including 4,285,725 Common Shares issued pursuant to the exercise of the over-allotment option, for aggregate gross proceeds of $23.0 million.

DIRECTORS AND OFFICERS

The names, province and country of residence, positions with the Corporation, and principal occupation of the directors and officers of the Corporation are set out below and in the case of directors, the period each has served as a director of the Corporation.

Name, Address and Position	Director Since[5]	Principal Occupation for the Previous 5 Years
Ray Smith Alberta, Canada Director and Chairman of the Board of Directors [1][2]	October 12, 2005	President and Chief Executive Officer of Bellatrix Exploration Ltd. since November 1, 2009. Prior thereto, President and Chief Executive Officer of True Energy Inc. (as administrator of True Energy Trust), from January, 2009 to November, 2009. Prior thereto, President and Chief Executive Officer of Cork Exploration Inc. from June, 2007 to November, 2007 and Chairman of Cork Exploration Inc. from April, 2005 to November, 2007.
Kevin Shaw Alberta, Canada Director, President and Chief Executive Officer	November 27, 2012	President and Chief Executive Officer of Madalena since November, 2012. Prior thereto, Managing Director & Head of Global Energy Research at a boutique investment bank from August 2011 to November 2012. Prior thereto, Senior Oil & Gas Research Analyst and Partner building a successful energy franchise at Wellington West Capital Markets from 2009 to July 2011 prior to Wellington's sale to National Bank Financial.. 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 Imperial Oil Limited.
Barry B. Larson Alberta, Canada Director [3]	July 21, 2010	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.
Keith Macdonald Alberta, Canada Director [1][2][3]	June 22, 2010	President of Bamako Investment Management Ltd., a private holding and financial consulting company, since July 1994. Chief Executive Officer and a director of EFLO Energy Inc. since March, 2011.
Jay Reid Alberta, Canada Director [2]	February 13, 2009	Partner at the 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 Corporate Secretary for Advantage Oil & Gas Ltd., Longview Oil Corp., Gear Energy Ltd. and Pinecrest Energy Inc. and also serves as a director or corporate secretary of three private issuers.
Ving Woo Alberta, Canada Director [1][3]	March 10, 2006	Vice-President and Chief Operating Officer of Bellatrix Exploration Ltd., since October 2010; prior thereto Vice President, Operations of Bellatrix Exploration Ltd. from November, 2009 to October, 2010. Prior thereto, Vice President, Operations of True Energy Inc. (as administrator of True Energy Trust), from April, 2009 to November, 2009. Prior thereto, director of Cork Exploration Inc.
Steve Dabner Alberta, Canada Vice President, Exploration	N/A	Vice President, Exploration of Madalena since November, 2012. Previously, President, Chief Executive Officer and Director of Online from January, 2011 to October, 2012. Prior thereto, independent businessman from June, 2007 to January, 2011.
Brent Foster Alberta, Canada Vice President, Engineering	N/A	Vice President, Engineering of Madalena since November, 2012. Previously, Vice President, Engineering of Online from January, 2011 to October, 2012. Prior thereto, independent businessman from 2010 to January 2011 and consultant to Intrepid Energy Corp. and EdgeStone Capital Partners from 2007 to 2010.
Thomas Love Alberta, Canada Vice President, Finance and Chief Financial Officer	N/A	Vice President, Finance and Chief Financial Officer of Madalena since February, 2013. Previously, Chief Financial Officer and Director of Online from January, 2011 to October, 2012. Prior thereto, independent businessman from June 2007 to January 26, 2011 and Chairman, Chief Financial Officer and Director of Trimox Energy Inc. from December 2004 until June 2007.
Robert D. Stanton Alberta, Canada Vice President, Operations	N/A	Vice President, Operations of Madalena since November, 2012. Previously, Vice President, Operations of Online from January, 2011 to October, 2012. Prior thereto, independent businessman from November, 2009 to January, 2011 and Vice-President, Engineering and Operations of Result Energy Inc. from January, 2005 to November, 2009.

Notes:

(1) Member of the Audit Committee.

(2) Member of the Corporate Governance and Compensation Committee.
(3) Member of the Reserves Committee.
(4) Bamako Investment Management Ltd., a company over which Mr. Macdonald exercises control, directly holds 300,000 of such Common Shares.
(5) 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 8,636,500 Common Shares, representing 2% of the issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

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.

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 2013 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 2013 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, 2013, 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 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 re-commissioned.

Downstream

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 factors primarily determine oil prices, however, prices are also influenced by regional market and transportation issues. The specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, 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 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), Intercontinental Exchange or the New York Mercantile Exchange (NYMEX) in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms. 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 came into force 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 that 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. The maximum royalty payable under the royalty regime is 40%.

Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula with the maximum royalty payable under the royalty regime set at 36%.

Producers of oil and natural gas from freehold lands in Alberta are required to pay freehold mineral tax. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands and is derived from the *Freehold Mineral Rights Tax Act* (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. The basic formula for the assessment of freehold mineral tax is: revenue less allocable costs equals net revenue divided by wellhead production equals the value based upon unit of production. If payors do not wish to file individual unit values, a default price is supplied by the Crown. On average, the tax levied is 4% of revenues reported from fee simple mineral title properties.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. For example, the Innovative Energy Technologies Program (the "**IETP**") 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.

In addition, 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 and horizontal non-project oil sands 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 if it decides to discontinue the program.

Land Tenure

The respective provincial governments predominantly own the rights to crude oil and natural gas located in the western provinces. Provincial government grant 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 such provinces 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.

Environmental Regulation

The oil and natural gas industry is currently subject to regulation pursuant to a variety of provincial and federal environmental legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for, among other things, restrictions and prohibitions on the spill, 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 with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, 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 and the imposition of material fines and penalties.

Federal

Pursuant the *Prosperity Act*, the Government of Canada amended or repealed several pieces of federal environmental legislation and in addition, created a new federal environment assessment regime that came in to force on July 6, 20121. 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.

Alberta

The regulatory landscape in Alberta has undergone a transformation from multiple regulatory bodies to a single regulator for upstream oil and gas, oil sands and coal development activity. On June 17, 2013, the Alberta Energy Regulator (the "**AER**") assumed the functions and responsibilities of the former Energy Resources Conservation Board, including those found under the

Oil and Gas Conservation Act ("**ABOGCA**"). On November 30, 2013, the AER assumed the energy related functions and responsibilities of Alberta Environment and Sustainable Resource Development ("**AESRD**") in respect of the disposition and management of public lands under the Public Lands Act. On March 29, 2014, the AER assumed the energy related functions and responsibilities of AESRD in the areas of environment and water under the *Environmental Protection and Enhancement Act and the Water Act*, respectively. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind the transformation to a single regulator is the creation of an enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

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 seven 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.

Proclaimed in force in Alberta on October 1, 2009, the *Alberta Land Stewardship Act* (the "**ALSA**") provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established under the ALSA are 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, licenses, registrations, 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 force on September 1, 2012. The LARP is the first of seven regional plans developed under the ALUF. LARP covers a region in the northeaster corner of Alberta that is approximately 93,212 square kilometres in size. The region includes a substantial portion of the Athabasca oilsands area, which contains approximately 82% of the province's oilsands resources and much of the Cold Lake oilsands area.

LARP establishes six new conservation areas and nine new provincial recreation areas. In conservation and provincial recreation areas, conventional oil and gas companies with pre-existing tenure may continue to operate. Any new petroleum and gas tenure issued in conservation and provincial recreation areas will include a restriction that prohibits surface access. In contrast, oilsands companies' tenure has been (or will be) cancelled in conservation areas and no new oilsands tenure will be issued. While new oil sands tenure will be issued in provincial recreation areas, new and existing oil sands tenure will prohibit surface access.

The next regional plan to take effect is the South Saskatchewan Regional Plan ("**SSRP**") which covers approximately 83,764 square kilometres and includes 45% of the provincial population. The SSRP was released in draft form in 2013 and is expected to come into force in the summer of 2014.

With the implementation of the new Alberta regulatory structure under the AER, AESRD will remain responsible for development and implementation of regional plans. However, the AER will take on some responsibility for implementing regional plans in respect of energy related activities.

Liability Management Rating Programs

Alberta

In Alberta, the AER implements the Licensee Liability Rating Program (the "**AB LLR Program**"). The AB LLR Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. The ABOGCA establishes an orphan fund (the "**Orphan Fund**") to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program if a licensee or working interest participant ("**WIP**") becomes defunct. The Orphan Fund is funded by licensees in the AB LLR Program through a levy administered by the AER. The AB LLR Program is designed to minimize the risk to the Orphan Fund posed by unfunded liability of licences and prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The AB LLR Program requires a licensee

whose deemed liabilities exceed its deemed assets to provide the AER with a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month and failure to post the required security deposit may result in the initiation of enforcement action by the AER.

Effective May 1, 2013, the AER implemented important changes to the AB LLR Program that resulted in a significant increase in the number of oil and gas companies in Alberta that are required to post security. Some of the important changes include:

- a 25% increase to the prescribed average reclamation cost for each individual well or facility (which will increase a licensee's deemed liabilities);
- a $7,000 increase to facility abandonment cost parameters for each well equivalent (which will increase a licensee's deemed liabilities);
- a decrease in the industry average netback from a five-year to a three-year average (which will affect the calculation of a licensee's deemed assets, as the reduction from five to three years means the average will be more sensitive to price changes); and
- a change to the present value and salvage factor, increasing to 1.0 for all active facilities from the current 0.75 for active wells and 0.50 for active facilities (which will increase a licensee's deemed liabilities).

These changes will be implemented over a three-year period. The first phase was implemented in May of 2013, the second phase will be implemented in May of 2014 and the final phase will be implemented in May of 2015. The changes to the LLR Program stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

Climate Change Regulation

Federal

The Government of Canada is a signatory to the *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and a participant to the Copenhagen Accord (a non-binding agreement created by the UNFCCC which represents a broad political consensus and reinforces commitments to reducing GHG emissions). On January 29, 2010, Canada inscribed in the Copenhagen Accord its 2020 economy-wide target of a 17% reduction of GHG emissions from 2005 levels. This target is aligned with the United States target. In a report dated October 2013, the Government stated that this target represents a significant challenge in light of strong economic growth (Canada's economy is projected to be approximately 31% larger in 2020 compared to 2005 levels).

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 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, for application to regulated sectors on a facility-specific, sector-wide basis or company-by-company basis. Although the intention was for draft regulations aimed at implementing the Updated Action Plan to become binding on January 1, 2010, the only regulations being implemented are in the transportation and electricity sectors. The federal government indicates that it is taking a sector-by-sector regulatory approach to reducing GHG emissions and is working on regulations for other sectors. 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. In June 2012, the second US-Canada Clean Energy Dialogue Action Plan was released. The plan renewed efforts to enhance bilateral collaboration on the development of clean energy technologies to reduce GHG emissions.

Alberta

As part of Alberta's 2008 Climate Change Strategy, the province committed to taking action on three themes: (a) conserving and using energy efficiently (reducing GHG emissions); (b) greening energy production; and (c) implementing carbon and capture storage.

As part of its efforts to reduce GHG emissions, Alberta introduced legislation to address GHG emissions: the Climate Change and Emissions Management Act (the "**CCEMA**") enacted on December 4, 2003 and amended 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 and aims for a 50% reduction from 1990 emissions relative to GDP by 2020.

The accompanying regulations include the *Specified Gas Emitters Regulation* ("**SGER**"), which imposes GHG limits, and the Specified Gas Reporting Regulation, which imposes GHG emissions reporting requirements. Alberta facilities emitting more than

100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their GHG emissions.

The SGER, effective July 1, 2007, applies to facilities emitting more than 100,000 tonnes of GHGs in 2003 or any subsequent year, and requires reductions in GHG emissions intensity (e.g. the quantity of GHG emissions per unit of production) from emissions intensity baselines established in accordance with the SGER. The SGER distinguishes 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 by 12% of their baseline emissions intensity for 2008 and subsequent years. Generally, the baseline for an Established Facility reflects the average of emissions intensity in 2003, 2004 and 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 SGER. New Facilities are required to reduce their emissions intensity by 2% from baseline in the fourth year of commercial operation, 4% of their baseline in the fifth year, 6% of their baseline in the sixth year, 8% of their baseline in the seventh year and 10% of their baseline in the eighth year. The CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA provides that 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 CO_2 equivalent. The funds contributed by industry to the Climate Change and Emissions Management Fund will be used to drive innovation and test and implement new technologies for greening energy production. Emissions credits can also 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.

Alberta is also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta will invest $2 billion into demonstration projects that will begin commercializing the technology on the scale needed to be successful. 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 and should not 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 Argentinean 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 licensing regime in Neuquén Province, Argentina where the Corporation's acreage is located could have a material adverse effect on the Corporation.

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.

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 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 oil and natural gas.

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, spills and 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 the Organization of the Petroleum Exporting Countries ("**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 from 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, sanctions imposed on certain oil

producing nations by other countries and 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 in accordance with 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;
- regulatory changes;

- 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, Pipeline Systems

The Corporation delivers its products through gathering and processing facilities 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 and processing facilities 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 market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems 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 have a materially adverse effect on the Corporation's ability to process its production and deliver the same for sale.

Competition

The petroleum industry is competitive in all of 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 affected adversely and materially. If the Corporation is unable to utilize the most advanced commercially available technology, its business, financial condition and results of operations could also be adversely affected in a material way.

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, natural gas 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 (including exploration, development, 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 regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the permits, licenses, registrations, approvals and authorizations 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 (the production of oil and natural gas). Specifically, hydraulic fracturing enables the production of 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 the spill, release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites.

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.

Liability Management

Alberta has developed a liability management program designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder becomes defunct. This program generally involves an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes of the ratio of the Corporation's deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted. This is of particular concern to junior oil and gas companies as they may e disproportionately affected by price instability. See "*Industry Conditions*".

Climate Change

Argentina is a signatory to the *United Nations Framework Convention on Climate Change* ("**UNFCCC**") 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 which may require the Corporation to comply with greenhouse gas ("**GHG**") 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 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 GHG emissions from 2005 levels by 2020. These GHG emission reduction targets are not binding, however. 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.

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 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. This 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. The actual interest of the Corporation in properties may accordingly 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 legislative changes, which affect the Corporation's title to the oil and natural gas properties the Corporation controls that 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 from such estimated reserves 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 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 therefore 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 continuously 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 the subject of 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 October 2013, following an application and approval process by Madalena and its partners over several months, the exploration period for Coiron Amargo Sur was extended until November 8, 2014 by way of an official decree signed by the Province of Neuquén in Argentina. The remaining work commitments in Coiron Amargo Sur are estimated at approximately USD$2.35

million plus VAT (net to Madalena) as of December 31, 2013. After satisfying these remaining work commitments, Madalena has the ability to extend Coiron Amargo Sur through further exploration, evaluation and/or exploitation (development) phases.

Cortadera Block

On January 15, 2014, the Corporation announced that, on the Cortadera Block, the joint venture partnership consisting of Apache Corporation, Gas y Petroleo del Neuquén SA and Madalena signed an amended contract agreement to formalize a multi-year agreement for the extension of the initial exploration period and inclusion of subsequent exploration periods. Subsequent to that agreement and following an application and approval process, the first exploration period for Cortadera was extended by way of an official decree which was signed by the Province of Neuquén in Argentina. This extension provides the partnership until October 26, 2014 to satisfy the remaining work commitments on the block, which involves the upcoming re-entry work.

Under the amended agreement, and subsequent to conducting the upcoming re-entry work, the partnership at Cortadera has the option to enter into subsequent exploration periods involving a second exploration period extending to October 25, 2018 and a third exploration upon which the partnership has the option to enter into subsequent exploration periods involving a second exploration period extending to October 25, 2021, or extend the Cortadera Block through potential further evaluation and/or exploitation phases.

The decree signed by the Province of Neuquén, as noted above, stipulates that Gas y Petroleo del Neuquén SA, which is the provincial petroleum company within the Province of Neuquén and is a working interest partner in the Cortadera Block, upwardly revised its carried working interest in the block to 15% from the previous 10%, resulting in a proportionate reduction of Madalena's working interest in the block to 37.8% compared to its previous 40% working interest.

Madalena and its new incoming partner (YPF S.A. post the purchase of the Apache subsidiary in Argentina) plan to re-enter the previously drilled CorS.x-1 Vaca Muerta test well to evaluate an up-hole zone of interest in the wellbore targeting the Mulichinco tight sand play. Madalena believes that its share of any work performed is not expected to be significant due to Apache's obligation to pay for the majority of the costs of the anticipated work program.

Curamhuele Block

In March 2012 the exploration period for the block was extended to November 8, 2013. The exploration block qualified for an additional one year extension after November 13, 2013. In June 2013, the exploration period was extended until November 8, 2014 by way of an official decree signed by the Province of Neuquén in Argentina. The remaining work commitments at Curamhuele are approximately US$13.8 million plus VAT as at December 31, 2013.

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 are the auditors of the Corporation and have confirmed that they are independent with respect to the Corporation within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations.

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 Energy Inc. (the "**Corporation**"):

1. We have evaluated the Corporation's reserves data as at December 31, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, 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, 2013, 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 Company, L.P..	Madalena Energy Inc. Coiron Amargo Block as at December 31, 2013 and prepared April 15, 2014	Argentina	Nil	23,167,585	Nil	23,167,585
TOTAL			**Nil**	**23,167,585**	**Nil**	**23,167,585**

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 Company, L.P.
Houston, Texas

Execution Date: April 15, 2014

(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 Energy Inc. (the "**Corporation**"):

1. We have evaluated the Corporation's reserves data as at December 31, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, 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, 2013, 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 Petroleum Consultants Ltd. Calgary, Alberta		Canada	Nil	25,578,900	Nil	25,578,900
TOTAL			**Nil**	25,578,900	**Nil**	25,578,900

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 28, 2014

(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 Energy Inc. (the "**Corporation**") is 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, 2013, 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 28 day of April, 2014.

(signed) *"Kevin Shaw"*
Kevin Shaw,
President & Chief Executive Officer and Director

(signed) *"Ving Y. Woo"*
Ving Y. Woo
Director and Chairman of the Reserves Committee

(signed) *"Thomas Love"*
Thomas Love
Vice-President Finance & Chief Financial Officer

(signed) *"Keith Macdonald"*
Keith Macdonald
Director