Annual Information Form

Year Ended December 31, 2015

April 21, 2016

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 Resources Inc., which was formerly a wholly-owned subsidiary of Madalena, with each Shareholder receiving one common share of Great Bear Resources Inc. 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 21, 2016;

"**ARS**" means Argentine peso;

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

"CAD" means Canadian dollars;

"**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.

"**First Mountain**" means First Mountain Exploration Inc.;

"GLJ" means GLJ Petroleum Consultants Ltd.;

"**GLJ Report**" means the report of GLJ dated February 29, 2016 evaluating the Argentine crude oil, natural gas liquids and natural gas reserves of the Corporation as at December 31, 2015;

"**Gran Tierra**" means Gran Tierra Energy Inc.;

"GTE Acquisition" means the acquisition of the Argentine business unit of Gran Tierra which closed on June 25, 2014;

"**GyP**" means Gas y Petroleo del Neuquén S.A., 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 February 17, 2016 evaluating the Canadian crude oil, natural gas liquids and natural gas reserves of the Corporation as at December 31, 2015;

"MEA" means Madalena Energy Argentina S.R.L (formerly "Gran Tierra Energy Argentina S.R.L."), an entity existing pursuant to the laws of Argentina and a subsidiary of the Corporation;

"**MPAL**" means Madalena Petroleum Americas Limited (formerly "Petrolifera Petroleum Limited"), an entity existing pursuant to the laws of Barbados and a wholly owned subsidiary of MPHL;

"**MPHL**" means Madalena Petroleum Holdings Limited (formerly "Petrolifera Petroleum Holdings Limited"), an entity existing pursuant to the laws of Barbados and a wholly owned subsidiary of MPL;

"**MPL**" means Madalena Petroleum Ltd. (formerly "Petrolifera Petroleum Ltd."), an entity existing pursuant to the laws of Canada and a wholly owned subsidiary of the Corporation;

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

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

"**NGL**" means natural gas liquids;

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

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

"**Online**" means Online Energy Inc.;

"**OTCQX**" means the OTCQX Best Market marketplace of the OTC Markets Group;

"**PETJA**" means Pet Ja S.A., an entity pursuant to the laws of Argentina and a subsidiary of MEA;

"**Point Loma"** means Point Loma Energy Ltd.;

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

"**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.;

"**USD**" means United States dollars; and

"**YPF**" means YPF S.A.

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

Selected Defined Oil & Gas Terms

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.

"**conventional natural gas**" means natural gas that has been generated elsewhere and has migrated as a result of hydrodynamic forces and is trapped in discrete accumulations by seals that may be formed by localized structural, depositional or erosional geological features;

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

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

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

"**development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from 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 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 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 referred to as "geological and geophysical costs");

(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;

"**forecast prices and costs**" means future prices and costs that are:

(a) generally accepted as being a reasonable outlook of the future; or

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Corporation is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in subparagraph (a);

"**future net revenue**" means a forecast of revenue, estimated using forecast prices and costs, arising from the anticipated development and production of resources, net of the associated royalties, operating costs, development costs, and abandonment and reclamation costs;

"**gross**" means:

(a) in relation to an entity's interest in production and reserves, its "company gross reserves", which are such entity's working interest (operating or non-operating) share before deduction of royalties and without including any royalty interest of such entity;

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

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

"**heavy crude oil**" means crude oil with a relative density greater than ten degrees API gravity and less than or equal to 22.3 degrees API gravity;

"**hydrocarbon**" means a compound consisting of hydrogen and carbon, which, when naturally occurring, may also contain other elements such as sulphur;

"**light crude oil**" means crude oil with a relative density greater than 31.1 degrees API gravity;

"**medium crude oil**" means crude oil with a relative density greater than 22.3 degrees API gravity and less than or equal to 31.1 degrees API gravity;

"**natural gas**" means a naturally occurring mixture of hydrocarbon gases and other gases;

"**natural gas liquids**" means those hydrocarbon components that can be recovered from natural gas as a liquid including, but not limited to, ethane, propane, butanes, pentanes plus, and condensates;

"**net**" means:

(a) in relation to an entity's interest in production and reserves, such entity's working interest (operating or non-operating) share after deduction of royalty obligations, plus the entity's royalty interests in production or reserves;

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

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

"**property**" includes:

(a) fee ownership or a lease, concession, agreement, permit, licence or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest;

(b) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and

(c) an agreement with a foreign government or authority under which a reporting issuer participates in the operation of properties or otherwise serves as "producer" of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer). A property does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas;

"**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;

"**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;

The qualitative certainty levels referred to in the definitions "probable reserves" and "proved reserves" 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.

"**reserves**" are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, 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. Reserves are classified according to the degree of certainty associated with the estimates;

"**resource play**" refers to drilling programs targeted at regionally distributed crude oil or natural gas accumulations; successful exploitation of these reservoirs is dependent upon technologies such as horizontal drilling and multi-stage fracture stimulation to access large rock volumes in order to produce economic quantities of oil or natural gas;

"**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;

"**shale gas**" means natural gas:

(a) contained in dense organic-rich rocks, including low-permeability shales, siltstones and carbonates, in which the natural gas is primarily adsorbed on the kerogen or clay minerals; and

(b) that usually requires the use of hydraulic fracturing to achieve economic production rates;

"**tight oil**" means crude oil: (a) contained in dense organic-rich rocks, including low-permeability shales, siltstones and carbonates, in which the crude oil is primarily contained in microscopic pore spaces that are poorly connected to one another; and (b) that typically requires the use of hydraulic fracturing to achieve economic production rates;

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

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

"**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.

Words importing the singular number only include the plural, and vice versa, and words importing any gender include all genders. All dollar amounts set forth in this annual information form are in USD, except where otherwise indicated.

ABBREVIATIONS

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

Other

AECO	EnCana Corp.'s natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
ºAPI	an indication of the specific gravity of crude oil measured on the API gravity scale
ARTC	Alberta Royalty Tax Credit
BOE, 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
BOE/d	BOE per day
Brent or Brent Crude	a blended crude stream produced in the North Sea region which serves as a reference or "marker" for pricing a number of other crude streams
m^3	cubic metres
Mboe	1,000 barrels of oil equivalent
Medanito	the Argentina in-country crude oil benchmark price
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 USD 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.**

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 2015 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 our 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 2006 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 OTCQX under the symbol "MDLNF".

The Corporation's principal office is located at 3200, 500 - 4th Avenue S.W., Calgary, Alberta, T2P 2V6, and the Corporation's registered office is located at Suite 2400, 525 - 8th Avenue S.W., Calgary, Alberta, T2P 1G1.

Inter-corporate Relationships

Madalena is involved in the exploration, development and production of oil and natural gas in Argentina and in Alberta, Canada.

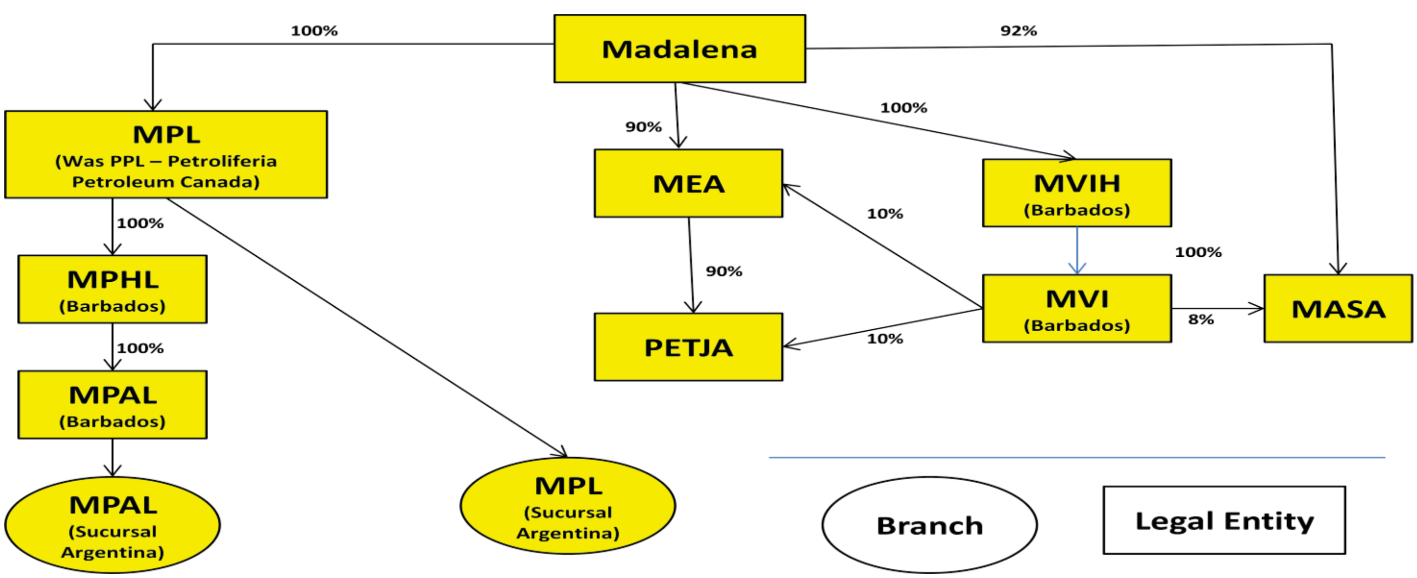
Prior to June 25, 2014, the Madalena group consisted of the following:

- Madalena Austral S.A. (Argentina)
- Madalena Ventures International Holding Company Inc. (Barbados)
- Madalena Ventures International Inc. (Barbados)

On June 25, 2014, the Corporation acquired the Argentine business unit of Gran Tierra and the following entities were added to the Madalena group:

- Madalena Petroleum Ltd. (Canada)
- Madalena Petroleum Holdings Limited (Barbados)
- Madalena Petroleum Americas Limited (Barbados)
- Madalena Energy Argentina S.R.L (Argentina)
- Pet-Ja S.A. (Argentina)

The corporate structure diagram is as follows:



GENERAL DEVELOPMENT OF THE BUSINESS

Madalena is an independent, Argentina focused, upstream oil and gas company.

Madalena holds approximately 950,000 net acres in four provinces of Argentina where it is focused on the delineation of large shale and unconventional resources in the Vaca Muerta shale, Lower Agrio shale, and Loma Montosa oil plays. The Corporation is implementing horizontal drilling and completions technology to develop both its conventional and resource plays.

Domestically, non-core Madalena operations are located in Western Canada in the Greater Paddle River area of west-central Alberta where the Corporation holds approximately 170 gross (130 net) sections of land (approximately 76% average W.I.) encompassing light oil and liquids-rich gas plays (collectively, the "**Canadian Assets**"). On February 8, 2016 Madalena announced that it has entered into a non-binding letter of intent with First Mountain and Point Loma to sell its non-core Canadian Assets (the "Proposed Transaction"). The Proposed Transaction is expected to close on May 31, 2016. See "*Recent Developments*".

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

YEAR 2013

Management and Board Changes

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 and assess other in-country opportunities, the Corporation retained RBC Capital Markets ("**RBC**") as Madalena's exclusive advisor related to its Neuquén basin assets in respect of a possible transaction. RBC acted as the strategic advisor to the GTE Acquisition.

Credit Facilities

On June 11, 2013, the Corporation increased its credit facilities with the National Bank of Canada. The revolving operating demand loan and the acquisition/development demand loan was increased from $4.7 million (CAD $4.75 million) to $9.8 million (CAD $10.0 million) and from $1.2 million (CAD $1.25 million) to $2.9 million (CAD $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 $7.0 million (CAD $7.25 million) through the issuance of:

(a) 11,765,000 Common Shares issued as CEE "flow-through" common shares within the meaning of the *Income Tax Act* (Canada) at a price of CAD $0.34 per share for gross proceeds of $3.9 million (CAD $4.0 million) by way of "bought deal" private placement; and

(b) (i) 200,000 Common Shares at a price of CAD $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 CAD $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 CAD $0.34 per share for gross proceeds of $ 3.1 million (CAD $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 $2.9 million (CAD $3.0 million).

December, 2013 Short Form Prospectus 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 CAD $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 $8.5 million (CAD $9.2 million).

YEAR 2014

February 2014 Short Form Prospectus Offering

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 CAD $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 $20.8 million (CAD $23.0 million).

June 2014 Short Form Prospectus Offering

On June 24, 2014, the Corporation closed a bought deal financing of 98,100,000 common shares at a price of CAD $0.51 per common share, for aggregate gross proceeds of $46.6 million (CAD $50.0 million).

GTE Acquisition

On June 25, 2014, the Corporation acquired all of the outstanding shares of the Argentine business unit of Gran Tierra for cash consideration of $55.4 million (CAD $59.2 million) (including acquired cash of $10.4 million (CAD $11.2 million) and 29,831,537 Common Shares at a deemed issue price of CAD $0.51 per Common Share.

July 2014 Over-allotment pursuant to Short Form Prospectus Offering

On July 7, 2014, the Corporation closed the over-allotment option in full of the $46.6 million (CAD $50 million) bought deal described above, issuing 14,715,000 common shares of the Corporation at a price of CAD $0.51 per common share for gross proceeds of $7.0 million (CAD $7.5 million).

Management Changes

Effective December 19, 2014, Mr. Brent Foster resigned from his position of Vice President - Engineering of the Corporation.

Effective December 1, 2014, Mr. Stephen Kapusta was appointed Head of Engineering for the Corporation and transitioned with Mr. Foster to assume his roles and responsibilities.

Significant Acquisitions

During the year ended December 31, 2014, Madalena completed the above noted GTE Acquisition, which was a "significant acquisition" within the meaning of that term in National Instrument 51-102 – *Continuous Disclosure Obligations*. A copy of the Business Acquisition Report, in respect of the GTE Acquisition, is available on SEDAR.

YEAR 2015

Shareholder Rights Plan

On May 26, 2015, Shareholder approval was received at the Corporation's annual and special meeting of Shareholders for the re-authorization of the Corporation's Rights Plan. 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.

Management and Board Changes

On January 26, 2015, Mr. Jay Reid resigned from his position as a director and Mr. Gus Halas was appointed Mr. Reid's replacement as a director of the Corporation. Mr. Ray Smith resigned from his position as Chairman of the Board and Mr. Steven Sharpe was elected Chairman of the Board.

On April 14, 2015, Mr. Doug Brooks resigned from his position as a director of the Corporation.

On May 26, 2015 Mr. Jay Reid was elected a director of the Corporation.

Effective August 31, 2015, Mr. Stephen Kapusta, the Head of Engineering for the Corporation, was appointed Vice President, Engineering for the Corporation.

Credit Facilities

On May 11, 2015, the Corporation authorized MEA, an indirect wholly owned subsidiary of the Corporation, to enter into an ARS loan agreement with Industrial and Commercial Bank of China S.A. with respect to a senior secured loan facility of up to ARS 90 million.

On October 13, 2015, the Corporation paid out its credit facility with National Bank of Canada. The facility was subsequently terminated.

OTCQX United States Public Market

On November 24, 2015 the Corporation's common shares commenced trading on the OTCQX, a top tier public market in the United States, under the symbol MDLNF.

RECENT DEVELOPMENTS

Management and Board Changes

On March 24, 2016, Madalena announced the departure of Mr. Kevin Shaw as President, Chief Executive Officer and director of the Corporation. Mr. Steven Sharpe, Chairman of the Board, was appointed Interim President and Chief Executive Officer and Mr. Eric Mark was appointed to the vacant director position effective immediately.

Proposed First Mountain Transaction

On February 8, 2016, First Mountain Exploration Inc. ("**First Mountain**"), Point Loma Energy Ltd. ("**Point Loma**") and Madalena entered into a non-binding letter of intent pursuant to which, among other things, it is proposed that Point Loma will acquire Madalena's non-core Canadian oil and gas assets (the "**Non-Core Canadian Assets**") for a deemed aggregate purchase price of approximately $4.0 million (CAD $5.5 million).

It is anticipated that the Corporation will sign the asset purchase and sale agreement ("**PSA**") within the next two weeks. Proceeds will consist of 14,522,823 common shares of Point Loma , with a deemed value of $1.8 million (CAD $2.5 million), as well as a five-year $2.2 million (CAD $3 million) secured convertible debenture, bearing interest at 3% per annum, payable at the end of the debenture term. The effective date of this PSA is expected to be May 1, 2016, with closing expected on or about May 31, 2016, subject to certain terms and conditions, including the completion of a financing by the purchaser, as well as the successful acquisition (the "**Acquisition**") of Point Loma by First Mountain. The Acquisition will involve an exchange of publicly traded First Mountain common shares (TSXV: FMX) for all of the outstanding common shares of Point Loma including those received by Madalena as proceeds of the PSA.

Retracted Offering and Acquisition

On March 1, 2016, the Corporation announced that it had entered into a letter of intent, as amended, to acquire the 10% working interest of one of its partners in the Coiron Amargo block for cash consideration of $8.0 million and that it had filed a preliminary short form prospectus in connection with a marketed public offering of Common Shares through a syndicate of agents for aggregate gross proceeds of up to CAD $27.0 million, to be priced in the context of the market. On March 14, 2016, Madalena announced that, due to prevailing market conditions, it elected not to proceed with such acquisition and offering.

Going Concern and Capital Commitments

On April 21, 2016 the Corporation filed its consolidated financial statements for the year ended December 31, 2015, which consolidated financial statements were prepared on the basis that the Corporation is a going concern and will continue to realize its assets and discharge its liabilities in the normal course of operations for the foreseeable future. Although the Corporation generated significant cash flows from operating activities in 2015, the cash flows were, in part, the result of a number of one-time positive events that will not be repeated in 2016. As at December 31, 2015, the Corporation has working capital of approximately $0.5 million and significant future capital commitments to develop its properties. Further, in January 2016 the Argentina government reduced the benchmark oil price by 10% from $75.00 to $67.50 per barrel. Forecasted cash flows from operating activities will not be sufficient to fund the 2016 and 2017 capital commitments.

The Corporation's business is capital intensive and additional capital is required on a periodic basis. As part of its business plan, the Corporation regularly evaluates sources of funding. In 2015, particular emphasis was placed on accessing debt financing. During the last eight months of 2015, Madalena was involved in discussions regarding a potential source of debt financing. The Corporation was unsuccessful in securing this funding as the terms and conditions of the facility were ultimately unacceptable to the Corporation. The current world-wide economic environment relating to the oil and gas industry has made access to capital challenging for many companies, Madalena included. As a result, although the Corporation exited 2015 with a largely unleveraged balance sheet (positive working capital of $0.5 million and a before tax, NPV10 proved plus probable reserves value of $127.2 million, with $2.0 of long-term bank debt and $1.6 million of other long-term liabilities), the Corporation continues to face liquidity challenges.

The ability of the Corporation to continue as a going concern is dependent upon Madalena's ability to access additional funding to meet its anticipated 2016 and 2017 capital commitments. Potential additional sources of capital include: (i) credit facilities on acceptable terms; (ii) proceeds from the sale of non-core assets; (iii) proceeds from equalization payments, if any, received from a possible partner at Curamhuele; and (iv) the issuance of equity on acceptable terms. There is no certainty that these and other strategies will be sufficient to permit the Corporation to continue as a going concern.

The need to raise capital to fund ongoing operations creates a material uncertainty that may cast significant doubt over Madalena's ability to continue as a going concern. The consolidated financial statements do not reflect adjustments in the carrying values of the assets and liabilities, expenses and the consolidated statements of financial position classifications that would be necessary if the going concern assumption were not appropriate. Such adjustments could be material.

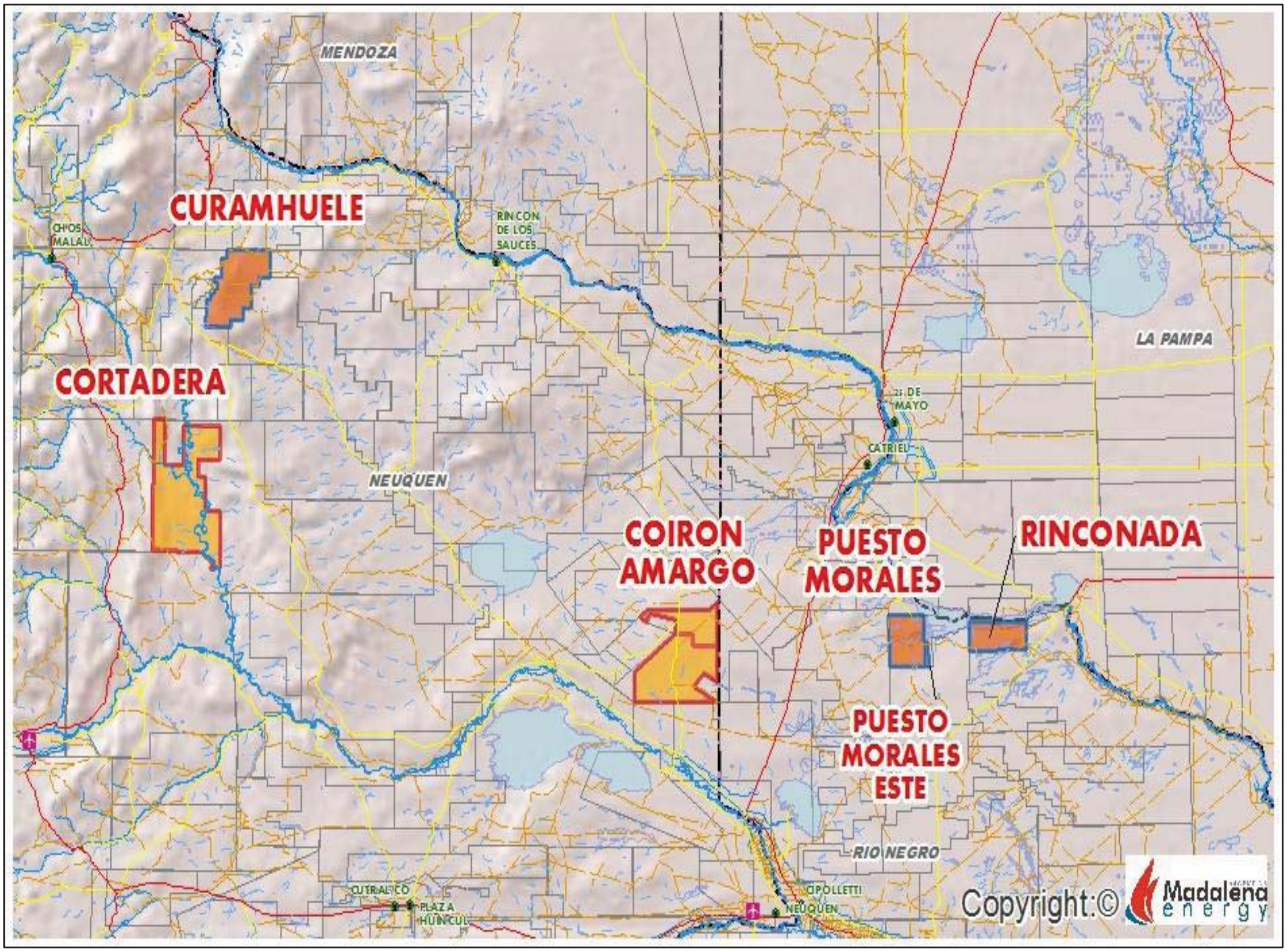
DESCRIPTION OF THE BUSINESS AND OPERATIONS

Overview

Madalena is an independent, Argentina focused, upstream oil and gas company.

Madalena holds approximately 950,000 net acres in four provinces of Argentina where it is focused on the delineation of large shale and unconventional resources in the Vaca Muerta shale, Lower Agrio shale and Loma Montosa oil plays. The Corporation is implementing horizontal drilling and completions technology to develop both its conventional and resource plays.

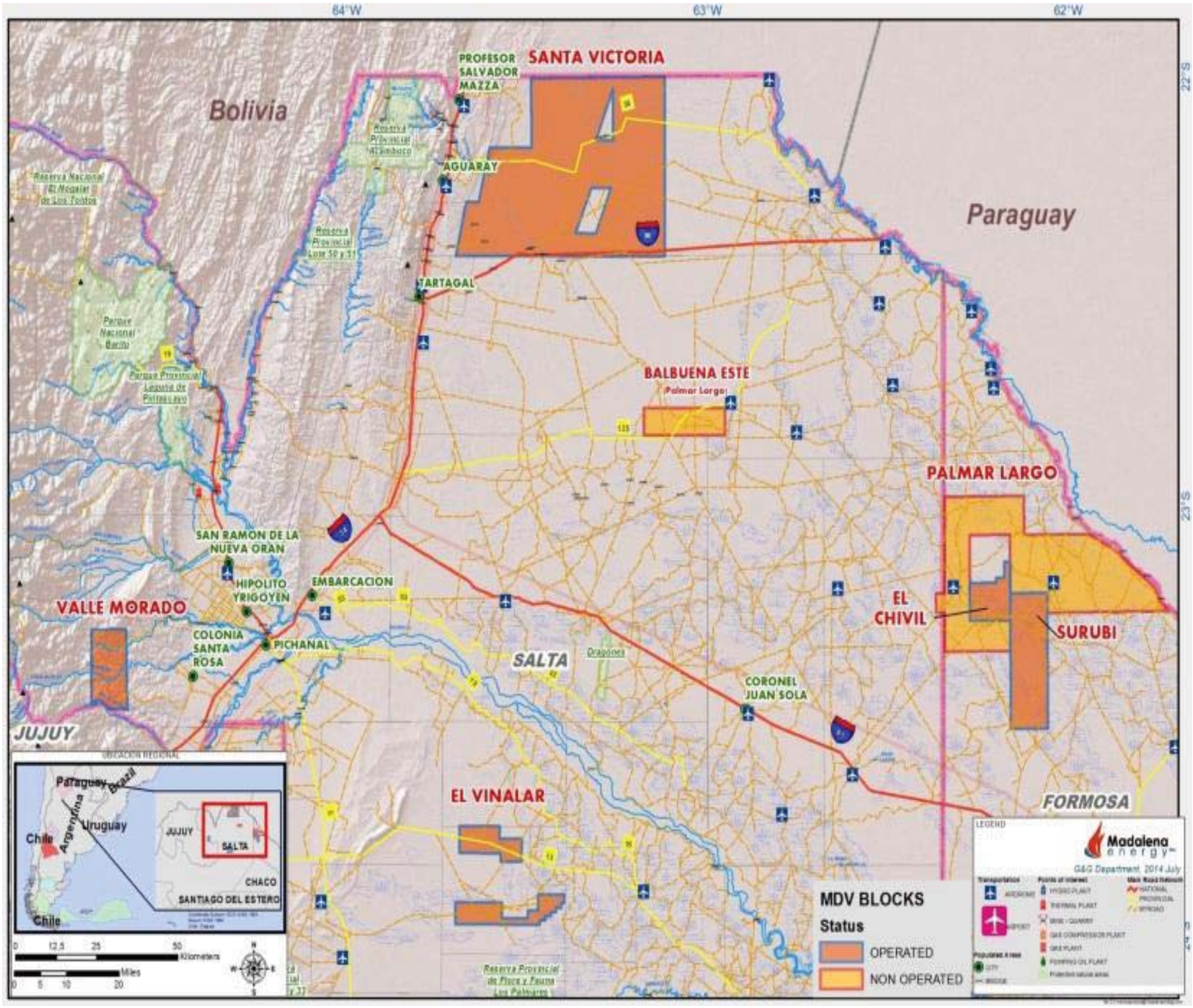
Argentine Operations – Neuquén basin



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, as set forth on the map above, in central-western Argentina. The basin stretches over a distance of 650 kilometres from north to 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.

The Corporation's Neuquén basin properties are comprised of producing and exploration opportunities including significant exposure to unconventional shale and tight oil and gas resources. The portfolio consists of six blocks, three in the Neuquén Province and three in the Rio Negro Province. The properties have extensive 2D and 3D seismic coverage and offsetting well data. The Neuquén basin is a highly prolific oil and gas producing basin that has extensive pipeline and facility infrastructure and a highly developed service industry. Major investments have been made by industry participants in the Neuquén basin on unconventional resource plays targeting the Vaca Muerta shale and recently, the Lower Agrio Shale. Madalena holds acreage positions in the Vaca Muerta shale, Lower Agrio shale and other resource plays including the Loma Montosa tight dolomite. In addition, Madalena produces conventional oil and gas reserves from multiple formations which have potential exploration and development upside.

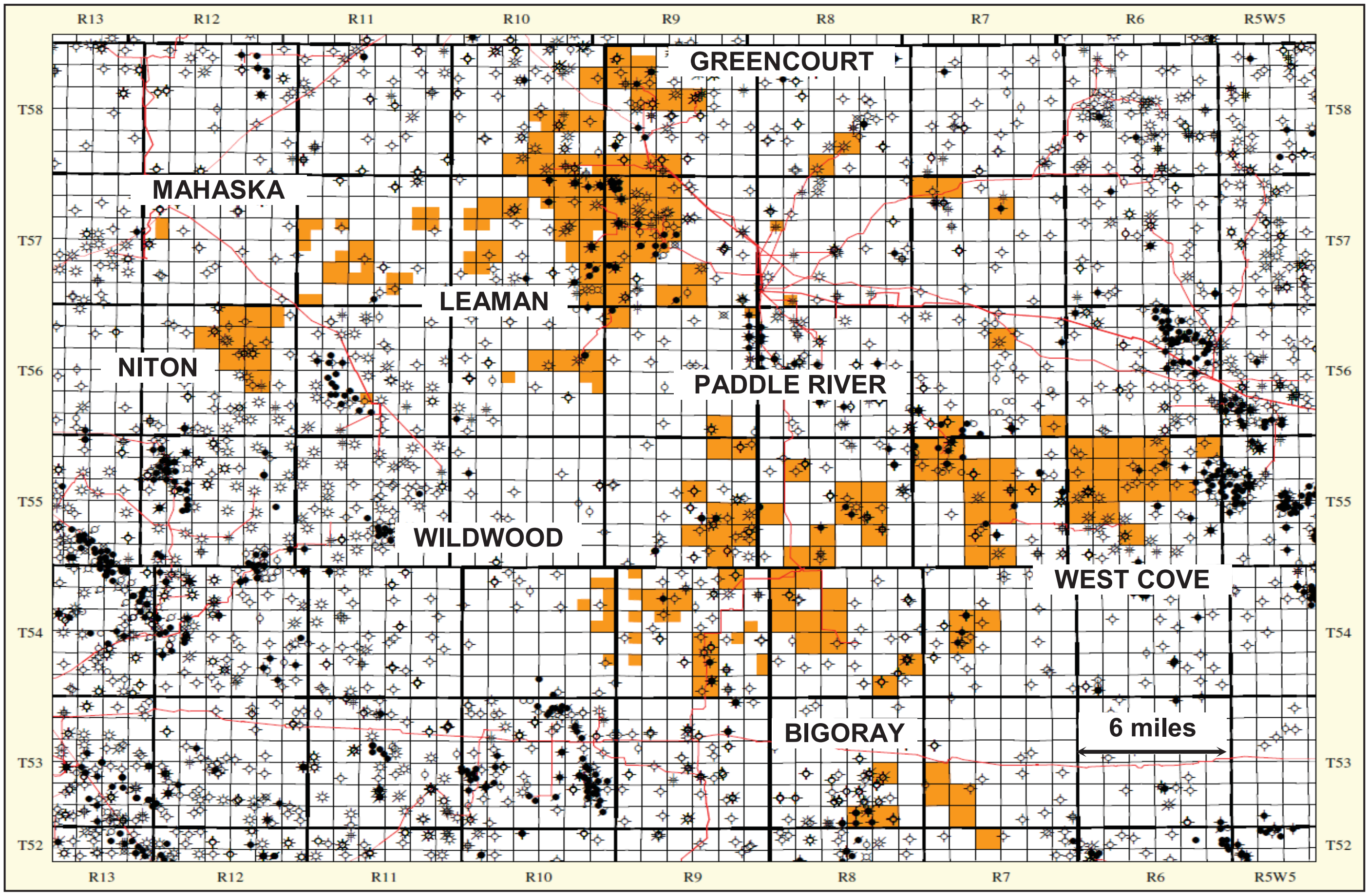
Argentine Operations – Noroeste basin



The Corporation's Noroeste basin assets, located in the northern part of Argentina, are as set forth on the map above. The portfolio consists of four producing (exploitation/development) blocks and two exploration blocks. Again, the Corporation has extensive 2D and 3D seismic coverage and offsetting well data. The Noroeste basin can have highly prolific oil and gas wells. There is gas infrastructure on the western edge of the basin. The central and eastern portions do not have gas infrastructure and consequently solution gas is flared or used to generate power. All of the Corporation’s oil producing blocks in this area are trucked to market. The service industry in this region is generally less developed than Neuquén resulting in longer lead times to arrange services. The basin remains relatively underexplored and has the potential for large conventional pools and unconventional resource plays.

The majority 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 – West-Central Alberta



Madalena's non-core area of operations is located in the Greater Paddle River area of west-central Alberta where, as at December 31, 2015, the Corporation held approximately 165 gross (approximately 124 net) sections of land (approximately 75% average W.I.) encompassing light oil and liquids-rich gas resource plays. As of February 8, 2016, Madalena has entered into the Proposed Transaction for 100% of these non-core assets located in the Greater Paddle River area. See "*Recent Developments*".

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 Argentine 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.

Argentina
There is a high utilization rate in Argentina for drilling rigs and other equipment and drilling or completion campaigns must be planned well in advance of the actual field activities taking place given the lengthy lead times required for the procurement of services. 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. The Corporation believes that the build out and modernization of the Argentina oil and gas service industry is continuing with new drilling rigs and specialized high rate and high pressure hydraulic fracturing equipment becoming more available on a regular basis.

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.

Marketing and Future Commitments

Argentina
All oil production 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 oil treatment plants and delivered directly to local refineries through pipelines or by trucking. Natural gas is produced in the Neuquén basin and sold into the local market. The Corporation utilizes third party plants for processing the natural gas and extracting NGL's. See *"Industry Conditions – Pricing and Marketing"*.

In Argentina, oil and gas companies are assigned blocks based on agreed to exploration, exploitation/development or evaluation phase type contracts whereby the partners on the block agree to certain commitments or work programs over a certain period of time. See "*Recent Developments-Going Concern and 2016 Capital Budget*" and "*Other Oil and Gas Information – Principal Properties – Argentina*".

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 and available routes to market, the value of refined products, the production targets of the Organization of Petroleum Exporting Countries ("**OPEC**") 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 National Energy Board ("**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issue of such a licence requires the approval of the Governor in Council.

The price of natural gas sold in interprovincial and international trade is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than two years or for a term of 2 to 20 years (in quantities of not more than 30,000 m^3/day), must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export licence from the NEB and the issue of such a licence requires the approval of the Governor in Council.

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

Social or Environmental Policies

The Corporation is actively engaged in Corporate Social Responsibility ("**CSR**") projects in all of its operated areas in Argentina. Madalena has employees assigned full time to CSR and also works alongside various Non-Government Organizations providing resources, educational support and training. In the Northern areas the focus is on basic needs working predominately with indigenous people. In the central area the focus is more institutional based. The Corporation works alongside and supports institutions like schools and local training centers.

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 2015, 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 a quarterly 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 38 office employees and 43 field employees in Argentina. The Corporation also utilizes the services of several professionals on a part-time contract or consulting basis. The Corporation intends to optimize in areas where efficiencies can be realized.

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**") as dated February 29, 2016 for the GLJ Report and February 17, 2016 for the McDaniel Report. The effective date of the statement is December 31, 2015. The reserves data set forth below (the "**Reserves Data**") is based upon evaluations by each of GLJ and McDaniel (collectively, the "**Reserve Engineers**").

The GLJ 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, 2015. 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, 2015. The Reserves Data conforms to the requirements of NI 51-101. Madalena engaged GLJ to provide evaluations of proved reserves and proved plus probable reserves in Argentina. Madalena engaged McDaniel to provide evaluations of proved reserves and proved plus probable reserves in Canada. 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. As at December 31, 2015, 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 "*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, 2015 using forecast prices and costs. All of the Corporation's properties are located in Argentina and Canada. Amounts shown are in USD for both Argentina and Canada. The McDaniel Report has been converted to USD based on the December 31, 2015 Bank of Canada noon spot exchange rate of USD$1 = CAD$1.3840 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, 2015

Forecast Prices and Costs

ARGENTINA	**Reserves**									
	Light/Medium Crude Oil		**Tight Oil**		**Conventional Natural Gas**		**Shale Gas**		**Natural Gas Liquids**	
	Gross (Mbbl)	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mboe)**	**Net (Mboe)**
Proved										
Developed Producing	2,867	2,417	-	-	2,301	1,902	-	-	47	46
Developed Non-Producing	515	435	10	8	178	151	8	7	1	1
Undeveloped	1,270	1,049	179	152	564	474	152	134	3	3
Total Proved	4,652	3,901	189	160	3,043	2,527	160	141	51	50
Probable	2,489	2,070	593	504	3,025	2,476	504	443	39	37
Total Proved Plus Probable	7,141	5,971	782	664	6,068	5,003	664	584	90	87

CANADA	**Reserves**					
	Light/Medium Crude Oil[(1)]		**Conventional Natural Gas**		**Natural Gas Liquids**	
	Gross (Mbbl)	**Net (Mbbl)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**
Proved						
Developed Producing	111	92	344	289	17	12
Developed Non-Producing	120	105	1,311	1,138	53	41
Undeveloped	-	-	-	-	-	-
Total Proved	231	197	1,654	1,427	70	53
Probable	324	281	6,485	5,148	248	167
Total Proved Plus Probable	555	478	8,139	6,575	318	220

Notes:
(1) Heavy crude oil of less than 0.5% of total oil reserves has been included.

TOTAL	Reserves									
	Light/Medium Crude Oil		Tight Oil		Conventional Natural Gas		Shale Gas		Natural Gas Liquids	
	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)	Gross (Mboe)	Net (Mboe)
Proved										
Developed Producing	2,978	2,509	-	-	2,645	2,191	-	-	64	58
Developed Non-Producing	635	540	10	8	1,489	1,289	8	7	54	42
Undeveloped	1,270	1,049	179	152	564	474	152	134	3	3
Total Proved	4,883	4,098	188	160	4,698	3,954	160	141	121	103
Probable	2,813	2,351	593	504	9,510	7,624	504	443	287	204
Total Proved Plus Probable	7,696	6,449	782	664	14,208	11,578	664	584	408	307

ARGENTINA	Net Present Values of Future Net Revenue USD										
	Before Income Taxes Discounted at (%/year)					After Income Taxes Discounted at (%/year)					$/BOE Unit Value Before tax Discounted at(1)
Reserves Category	0% MM	5% MM	10% MM	15% MM	20% MM	0% MM	5% MM	10% MM	15% MM	20% MM	10%
Proved											
Developed Producing	56.8	53.2	49.3	45.7	42.6	48.7	46.2	43.1	40.2	37.5	17.7
Developed Non-Producing	16.8	13.6	11.2	9.4	8.0	13.2	10.6	8.7	7.2	6.0	23.9
Undeveloped	29.2	19.5	12.8	8.1	4.6	21.3	13.2	7.6	3.6	0.8	9.8
Total Proved	102.8	86.3	73.3	63.2	55.2	83.2	70.0	59.4	50.9	44.2	16.1
Probable	96.9	68.8	50.6	38.3	29.6	62.3	42.2	29.4	20.7	14.6	16.3
Total Proved Plus Probable	199.7	155.0	124.0	101.5	84.8	145.4	112.2	88.7	71.6	58.8	16.2

CANADA	Net Present Values of Future Net Revenue USD										
	Before Income Taxes Discounted at (%/year)					After Income Taxes Discounted at (%/year)					$/BOE Unit Value Before tax Discounted at(1)
Reserves Category	0% MM	5% MM	10% MM	15% MM	20% MM	0% MM	5% MM	10% MM	15% MM	20% MM	10%
Proved											
Developed Producing	0.1	0.3	0.3	0.3	0.3	0.1	0.3	0.3	0.3	0.3	2.76
Developed Non-Producing	1.4	1.3	1.1	0.9	0.8	1.4	1.3	1.1	0.9	0.8	4.54
Undeveloped	-	-	-	-	-	-	-	-	-	-	-
Total Proved	1.6	1.6	1.4	1.3	1.2	1.6	1.6	1.4	1.3	1.2	3.98
Probable	6.1	3.5	1.8	0.6	(0.3)	6.1	3.5	1.8	0.6	(0.3)	1.88
Total Proved Plus Probable	7.7	5.1	3.2	1.9	0.9	7.7	5.1	3.2	1.9	0.9	2.45

TOTAL	Net Present Values of Future Net Revenue USD										
	Before Income Taxes Discounted at (%/year)					After Income Taxes Discounted at (%/year)					$/BOE Unit Value Before tax Discounted at[1]
Reserves Category	0% MM	5% MM	10% MM	15% MM	20% MM	0% MM	5% MM	10% MM	15% MM	20% MM	10%
Proved											
Developed Producing	56.9	53.5	49.6	46.0	42.9	48.8	46.5	43.4	40.5	37.8	14.2
Developed Non-Producing	18.2	14.9	12.3	10.3	8.8	14.6	11.9	9.8	8.1	6.8	13.0
Undeveloped	29.2	19.5	12.8	8.1	4.6	21.3	13.2	7.6	3.6	0.8	8.1
Total Proved	104.3	87.9	74.7	64.5	56.3	84.7	71.6	60.8	52.2	45.4	12.5
Probable	103.0	72.3	52.4	38.9	29.3	68.4	45.7	31.2	21.3	14.3	9.8
Total Proved Plus Probable	207.3	160.2	127.1	103.4	85.6	153.1	117.3	92.0	73.5	59.7	11.2

Notes:

(1) Unit values are based on Corporation Net Reserves.

Total Future Net Revenue (Undiscounted) at December 31, 2015

Forecast Prices and Costs USD

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 - USD								
Total Proved Reserves	346.8	55.9	130.5	43.2	14.5	102.8	19.6	83.2
Total Proved Plus Probable Reserves	588.1	95.7	185.3	92.7	14.8	199.7	54.3	145.4

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 - USD								
Total Proved Reserves	17.1	2.2	11.0	1.3	1.1	1.6	-	1.6
Total Proved Plus Probable Reserves	63.8	10.4	33.7	10.4	1.6	7.8	-	7.8

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 - USD								
Total Proved Reserves	363.9	58.1	141.5	44.5	15.6	104.4	19.6	84.8
Total Proved Plus Probable Reserves	651.9	106.1	219.0	103.1	16.4	207.5	54.3	153.2

CAD converted to USD based on the December 31, 2015 Bank of Canada noon spot exchange rate of USD$1 = CAD$1.3840.

Future Net Revenue by Productive Type
at December 31, 2015

Argentina	Net Present Value of Future Net Revenue (before deducting Future Income Tax Expenses and Discounted at 10%/year) (USD MM)	Unit Value (before deducting Future Income Tax Expenses and Discounted at 10%/year) (USD $/boe)(3)
Proved reserves		
Light Crude Oil and Medium Crude Oil(1)	69.1	16.8
Tight Crude Oil(1)	2.5	13.3
Conventional Natural Gas(2)	1.8	7.2
Total Proved	73.4	16.1
Proved plus Probable reserves		
Light Crude Oil and Medium Crude Oil(1)	106.2	16.8
Tight Crude Oil(1)	14.0	18.3
Conventional Natural Gas(2)	3.8	6.6
Total Proved Plus Probable reserves	124.0	16.2

Canada	Net Present Value of Future Net Revenue (before deducting Future Income Tax Expenses and Discounted at 10%/year) (USD MM)	Unit Value (before deducting Future Income Tax Expenses and Discounted at 10%/year) (USD $/boe)(3)
Proved reserves		
Light Crude Oil and Medium Crude Oil(1)	2.0	10.3
Conventional Natural Gas(2)	(0.5)	(2.2)
Total Proved	1.5	3.9
Proved plus Probable reserves		
Light Crude Oil and Medium Crude Oil(1)	3.7	7.9
Conventional Natural Gas(2)	(0.5)	(0.2)
Total Proved Plus Probable reserves	3.2	1.8

TOTAL	Net Present Value of Future Net Revenue (before deducting Future Income Tax Expenses and Discounted at 10%/year) (USD MM)	Unit Value (before deducting Future Income Tax Expenses and Discounted at 10%/year) (USD $/boe)(3)
Proved reserves		
Light Crude Oil and Medium Crude Oil(1)	71.1	16.5
Tight Crude Oil(1)	2.5	13.3
Conventional Natural Gas(2)	1.3	2.8
Total Proved	74.9	15.1
Proved plus Probable reserves		
Light Crude Oil and Medium Crude Oil(1)	109.9	16.2
Tight Crude Oil(1)	13.9	18.3
Conventional Natural Gas(2)	3.3	1.0
Total Proved Plus Probable reserves	127.1	13.5

Notes:
(1) Including solution gas and other by-products.
(2) Including by-products, but excluding solution gas and by-products from oil wells.
(3) Unit values are based on net reserve volumes.

Pricing Assumptions

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

GLJ employed the following pricing, exchange rate and inflation rate assumptions as of December 31, 2015 in the GLJ Report in estimating reserves data using forecast prices and costs. GLJ is independent of the Corporation

Summary of Pricing and Inflation Rate Assumptions
at December 31, 2015
Forecast Prices and Costs

	World	Argentina Domestic			
Year	Brent Price USD/bbl	Medanito Oil Price USD/bbl	Condensate USD/bbl	NGL Price USD/bbl	Gas Price USD/ MMbtu
2016	45.00	67.50	72.00	22.50	4.50
2017	54.00	67.50	72.00	22.50	4.50
2018	61.00	67.50	72.00	22.50	4.59
2019	67.00	67.50	72.00	22.50	4.68
2020	73.00	67.50	72.00	22.50	4.78
2021	78.00	69.10	73.71	23.03	4.87
2022	83.00	73.85	78.77	24.62	4.97
2023	88.00	78.60	83.84	26.20	5.07
2024	91.39	81.82	87.28	27.27	5.17
2025	93.22	83.56	89.13	27.85	5.27

Notes:
(1) Escalation at 2% per year after 2025.
(2) All costs escalate at 2% per year from 2016.
(3) Argentine gas price represents industrial contract prices received in the area. Weighted average historical prices realized by the Corporation for year ended December 31, 2015 from its Argentina oil and gas properties was $74.60 /bbl for crude oil and NGL's and $4.84/Mcf for natural gas.
(4) Well abandonment and reclamation costs for all existing wells and future wells associated with properties to which reserves have been assigned have been included at the property level. Additional abandonment and reclamation costs associated with pipelines and facilities or wells associated with properties not assigned reserves have not been included in this analysis.
(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 GLJ were accepted by GLJ as represented. No field inspection was conducted.

McDaniel employed the following pricing, exchange rate and inflation rate assumptions relating to the Canadian reserves as of December 31, 2015 in the McDaniel Report in estimating reserves data using forecast prices and costs. McDaniel is independent of the Corporation.

Year	WTI Cushing Oklahoma 40° API(1) (USD/bbl)	Edmonton Par Price 40° API(2) (CAD/bbl)	Edmonton Condensate (CAD/bbl)	Edmonton Propane (CAD/bbl)	AECO - C Spot CAD/MMbtu)	Exchange Rate (USD/CAD)
2016	45.00	56.60	60.60	10.60	2.70	0.730
2017	53.60	66.40	70.50	18.00	3.20	0.750
2018	62.40	72.80	77.00	25.90	3.55	0.800
2019	69.00	80.90	85.10	30.30	3.85	0.800
2020	73.10	83.20	87.50	31.20	3.95	0.825
2021	77.30	88.20	92.60	33.10	4.20	0.825
2022	81.60	93.30	97.80	34.90	4.45	0.825
2023	86.20	98.70	103.30	37.00	4.70	0.825
2024	87.90	100.70	105.40	37.70	4.80	0.825
2025	89.60	102.60	107.40	38.50	4.90	0.825

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) Escalation at 2% per year after 2029.

(4) The weighted average realized sales prices before hedging for the year ended December 31, 2015 were $2.17/Mcf for natural gas $35.44 /bbl for light and medium crude oil.

Reconciliation of Changes in Reserves

The following tables set out the reconciliation of the Corporation's gross reserves as at December 31, 2015 compared to December 31, 2014 based on forecast prices and costs by principal product type:

ARGENTINA FACTORS	--------- Light and Medium Crude Oil -----------			--------- Tight Crude Oil -----------		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2014	4,350	2,473	6,823	43	62	105
Extensions	542	661	1,203	146	531	677
Improved Recovery	-	-	-	-	-	-
Technical Revisions	985	(517)	468	-	-	-
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	(244)	(127)	(371)	-	-	-
Production	(982)	-	(982)	-	-	-
December 31, 2015	4,652	2,489	7,141	188	593	781

ARGENTINA FACTORS	--------- Natural Gas Liquids-----------			------------ Conventional Natural Gas -----------		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2014	70	74	143	4,131	4,328	8,459
Extensions	1	1	1	27	36	63
Improved Recovery	-	-	-	-	-	-
Technical Revisions	3	(35)	(32)	497	(1,417)	(920)
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	(1)	-	(1)	(193)	78	(115)
Production	(21)	-	(21)	(1,419)	-	(1,419)
December 31, 2015	51	39	90	3,043	3,025	6,068

ARGENTINA FACTORS	--------- Shale Gas -----------		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2014	-	-	-
Extensions	152	499	651
Improved Recovery	-	-	-
Technical Revisions	8	5	13
Discoveries	-	-	-
Acquisitions	-	-	-
Dispositions	-	-	-
Economic Factors	-	-	-
Production	-	-	-
December 31, 2015	160	504	664

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, 2014	314	366	680	47	18	65
Extensions	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions	(35)	(42)	(77)	(47)	(18)	(65)
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	(48)	-	(48)	-	-	-
December 31, 2015	231	324	555	-	-	-

CANADA FACTORS	Natural Gas Liquids Proved (Mbbl)	Natural Gas Liquids Probable (Mbbl)	Natural Gas Liquids Proved Plus Probable (Mbbl)	Conventional Natural Gas Proved (MMcf)	Conventional Natural Gas Probable (MMcf)	Conventional Natural Gas Proved Plus Probable (MMcf)
December 31, 2014	240	209	449	4,427	6,489	10,916
Extensions	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions	(167)	39	(128)	(2,662)	(4)	(2,667)
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	(3)	-	(3)	(110)	-	(110)
December 31, 2015	70	248	318	1,655	6,485	8,139

TOTAL FACTORS	Light and Medium Crude Oil Proved (Mbbl)	Light and Medium Crude Oil Probable (Mbbl)	Light and Medium Crude Oil Proved Plus Probable (Mbbl)	Heavy Oil Proved (Mbbl)	Heavy Oil Probable (Mbbl)	Heavy Oil Proved Plus Probable (Mbbl)
December 31, 2014	4,664	2,839	7,503	47	18	65
Extensions	542	661	1,203	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions	950	(559)	391	(47)	(18)	(65)
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	(244)	(127)	(371)	-	-	-
Production	(1,030)	-	(1,030)	-	-	-
December 31, 2015	4,882	2,814	7,696	-	-	-

TOTAL FACTORS	Tight Oil Proved (Mbbl)	Tight Oil Probable (Mbbl)	Tight Oil Proved Plus Probable (Mbbl)	Natural Gas Liquids Proved (Mbbl)	Natural Gas Liquids Probable (Mbbl)	Natural Gas Liquids Proved Plus Probable (Mbbl)
December 31, 2014	43	62	105	310	283	592
Extensions	146	531	677	1	1	1
Improved Recovery	-	-	-	-	-	-
Technical Revisions	-	-	-	(164)	4	(160)
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	(1)	-	(1)
Production	-	-	-	(24)	-	(24)
December 31, 2015	189	593	782	122	288	408

TOTAL FACTORS	----------- Conventional Natural Gas ------- ----------- Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	------------------- Shale Gas ---------------------- Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2014	8,558	10,817	19,375	-	-	-
Extensions	27	36	63	152	499	651
Improved Recovery	-	-	-	-	-	-
Technical Revisions	(2,165)	(1,421)	(3,587)	8	5	13
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	(193)	78	(115)	-	-	-
Production	(1,529)	-	(1,529)	-	-	-
December 31, 2015	4,698	9,510	14,207	160	504	664

Notes:
(1) Columns may not add due to rounding.

The Corporation had significant negative reserve revisions in Canada due to surface and facility issues. Operations at a third party gas plant were suspended due to low commodity pricing. This affected most of the gas and NGL producing wells. The Corporation has identified a project to tie-in a number of these wells to an alternate gas plant. The majority of these reserves are included in the Proved Non-Producing category. In 2015 there was no acquisition or drilling activity in Canada and hence, no reserve additions through extensions or discoveries.

In Argentina, positive technical revisions for proved case of 985 Mbbls were approximately 50% related to better performance at El Surubi. The balance of the positive revisions was a result of better performance at Puesto Morales, Coiron Amargo, and El Chivil. Higher fuel gas consumption and shrinkage at Puesto Morales resulted in a negative gas revision of 920 mmcf for the proved plus probable case. The Corporation had total light oil extensions of 1,203 Mbbls primarily as a result of a successful horizontal multi frac well drilled at Puesto Morales. The positive result allowed the booking of six additional offset wells to the reserve report for a total of 12 proved plus probable locations at Puesto Morales.

The new additions for Tight Oil and Shale Gas are predominately from three (1.05 net) horizontal multi-frac re-entries in the Vaca Muerta shale at Coiron Amargo.

Undeveloped Reserves

Undeveloped reserves are attributed by McDaniel and GLJ 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 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, 2015, 2014 and 2013 and, in the aggregate, before that time based on forecast prices and costs.

See "*Other Oil and Gas Information - Principal Properties*" and "*Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor – 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)		Tight Oil (Mbbl)		NGLs (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2013	314	383	-	-	-	-
2014	734	982	-	-	8	8
2015	822	1,270	179	179	3	3

Year	Conventional Natural Gas (MMcf)		Shale Gas (MMcf)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2013	393	459	-	-
2014	771	1,028	-	-
2015	113	564	152	152

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. This is the case for six proved undeveloped horizontal wells at Puesto Morales and two (0.7 net) horizontal wells at Coiron Amargo. GLJ has assigned 1.6 MMboe of proved undeveloped reserves in the GLJ Report with $40.2 million of associated undiscounted capital, of which $35.0 million is forecast to be spent in the first two years.

Probable Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Tight Oil (Mbbl)		NGLs (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2013	174	262	-	-	-	-
2014	1,389	1,521	-	-	44	44
2015	1,103	1,893	587	587	4	26

Year	Conventional Natural Gas (MMcf)		Shale Gas (MMcf)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2013	210	311	-	-
2014	2,078	2,245	-	-
2015	266	1,825	499	499

Probable undeveloped reserves have been assigned in areas where the reserves can be estimated with less certainty. In most instances, probable undeveloped reserves will be assigned on lands offsetting existing producing wells within the same accumulation or pool but there is some uncertainty as to whether they are directly analogous. It is equally likely that the actual remaining quantities will be greater or less that the proved plus probable reserves. In the GLJ Report, there are six additional probable undeveloped horizontal wells at Puesto Morales and three (1.05) net horizontal Vaca Muerta wells at Coiron. GLJ has assigned 2.9 MMboe of probable undeveloped reserves in the GLJ Report with $49.4 million of associated undiscounted capital, of which $25.2 million is forecast to be spent in the first two years.

CANADA

Proved Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Conventional Natural Gas (MMcf)		NGLs (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2013	-	-	-	1,735	-	43
2014	-	-	-	-	-	-
2015	-	-	-	-	-	-

There were no proved undeveloped reserves as of December 31, 2015.

Probable Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Conventional Natural Gas (MMcf)		NGLs (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2013	212	233	740	3,234	40	105
2014	192	217	926	5,049	35	139
2015	-	217	-	4,943	-	137

McDaniel has assigned 1,178 Mboe of probable undeveloped reserves in the McDaniel Report with $9.1 million of associated, undiscounted capital, to be spent in the first two years. The Probable Undeveloped reserves are associated with two gas wells at Niton and four (2.4 net) oil wells in the Paddle River / Westcove area.

TOTAL

Proved Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Tight Oil (Mbbl)		NGLs (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2013	314	383	-	-	-	43
2014	734	982	-	-	8	8
2015	822	1,270	179	179	3	3

Year	Conventional Natural Gas (MMcf)		Shale Gas (MMcf)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2013	393	2,194	-	-
2014	771	1,028	-	-
2015	113	564	152	152

GLJ has assigned 1.6 MMboe of proved undeveloped reserves in the GLJ Report with $40.2 million of associated undiscounted capital, of which $35.0 million is forecast to be spent in the first two years. There are no proven undeveloped reserves in Canada.

Probable Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Tight Oil (Mbbl)		NGLs (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2013	386	495	-	-	40	105
2014	1,581	1,738	-	-	79	183
2015	1,103	2,110	587	587	4	163

Year	Conventional Natural Gas (MMcf)		Shale Gas (MMcf)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2013	950	3,545	-	-
2014	3,004	7,294	-	-
2015	266	6,768	499	499

GLJ and McDaniel have collectively assigned 4,071 Mboe of probable undeveloped net reserves in the Reserve Reports with $49.3 million of associated undiscounted capital, of which $34.3 million is forecast to be spent in the first two years.

Significant Factors or Uncertainties

The oil and gas properties of the Corporation have no material extraordinary risks or uncertainties beyond those which are inherent of an oil and gas producing company

The GLJ report has assumed the successful ten year contract extension for certain leases in Argentina. The recently amended National Hydrocarbon Law ("**NH Law**") (see "*Industry Conditions – Argentina - Oil and Gas Industry Regulations*") has provided some clarification to the calculation of the renewal bonus. The GLJ report has included these assumptions for contract renewal terms on the El Chivil, El Vinalar and Palmar Largo properties. Notwithstanding this, there can be no certainty to a successful contract renewal for these properties and hence, the Corporation may not realize the future net revenues from these properties beyond their initial expiry date.

General

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.

Abandonment and Reclamation Costs

Abandonment and reclamation costs have been estimated by GLJ and McDaniel in the GLJ and McDaniel Reports and attributed to all properties that have been assigned reserves in the GLJ and McDaniel Reports and have been taken into account by GLJ and McDaniel in determining reserves that should be attributed to a property and in determining the aggregated future net revenue therefrom. No allowances were made, however, for the abandonment and reclamation of any pipelines. In addition, the Corporation does not recognize abandonment and reclamation obligations on facilities in Argentina where it has determined that there is no legal or constructive obligation to perform such activities.

Madalena will be liable for its share of ongoing environmental obligations and for the ultimate reclamation of the surface leases, wells, facilities and pipelines held by it upon abandonment. Ongoing environmental obligations are expected to be funded out of cash flow.

Madalena estimates well abandonment costs on a well-by-well basis using historical costs supplemented by current industry costs and changes in regulatory requirements. Estimated costs of well site abandonment and reclamation were included in the Reserve Reports 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 well-by-well 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 with no assigned reserves in either of the Reserve Reports while estimates for those costs are included in the financial statements. 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 Reserve Reports.

The Corporation has estimated the net cost to abandon and reclaim all existing wells and facilities to be $26.5 million (undiscounted and uninflated) as at December 31, 2015. These costs relate to wells and facilities on properties that may or may not have reserves attributed to them. As included in the estimate of future net revenue, GLJ and McDaniel have used a net cost to abandon and reclaim wells of $17.0 million (undiscounted and un-inflated) as at December 31, 2015. This estimate includes the cost to abandon and reclaim all future facilities and undrilled wells that have been attributed reserves but it excludes such costs where reserves have not been assigned.

The Corporation has 301.0 gross (218.7 net) wells for which it expects to incur abandonment and reclamation costs.

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

	Future Development Costs (USD M)	
Year	Total Proved Reserves	Total Proved Plus Probable Reserves
2016	9,103	17,683
2017	27,562	44,326
2018	6,529	30,645
2019	-	-
2020	-	-
Total (Undiscounted)	43,194	92,654
Total (Discounted at 10%)	37,713	79,429

CANADA[1]

	Future Development Costs (USD M)	
Year	Total Proved Reserves	Total Proved Plus Probable Reserves
2016	1,264	5,585
2017	-	4,795
2018	-	-
2019	-	-
2020	-	-
Total (Undiscounted)	1,264	10,380
Total (Discounted at 10%)	1,231	9,529

TOTAL

	Future Development Costs (USD M)	
Year	Total Proved Reserves	Total Proved Plus Probable Reserves
2016	10,367	23,268
2017	27,562	49,121
2018	6,529	30,645
2019	-	-
2020	-	-
Total (Undiscounted)	44,458	103,034
Total (Discounted at 10%)	38,944	88,958

1. CAD converted to USD based on the December 31, 2015 Bank of Canada noon spot exchange rate of USD$1 = CAD$1.3840.

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), farm outs or similar arrangements and strategic financial partnerships 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, 2015. Unless otherwise indicated, production stated is average daily production for the year ended December 31, 2015 received by the Corporation in respect of its working interest share before deduction of royalties and without including any royalty interest.

ARGENTINA

Madalena's Argentina properties are located in the Noroeste Basin in northern Argentina and the Neuquén Basin in central Argentina. On June 25, 2014, the Corporation acquired all of the outstanding shares of the Argentine business unit of Gran Tierra for cash consideration of $55.4 million (CAD $59.2 million), including cash of $10.4 million (CAD $11.2 million) and 29,831,537 common shares at a fair value of CAD $0.51 per common share. The GTE Acquisition significantly increased its Argentina reserves, production and undeveloped land position and added a fully functional independent business unit in Argentina, with an experienced technical and operational team.

The properties acquired include Puesto Morales, Puesto Morales Este, Valle Morado, El Surubi, El Chivil, Palmar Largo, El Vinalar, and Santa Victoria comprising approximately 821,200 net acres.

Madalena's primary producing concessions are at El Surubi, Puesto Morales and Coiron Amargo. During the quarter ended December 31, 2015, these blocks averaged 2,670 BOE/d or 86% of our consolidated Argentina production. Puesto Morales Block is the largest at 1,308 BOE /d (42%), El Surubi Block averaged 930 bbls/d (30%), while Coiron Amargo was at 433 BOE/d (14%). Other producing concessions include, El Chivil, El Vinalar and Palmar Largo. All concessions produce oil and Puesto Morales and Coiron Amargo also produce natural gas. Cortadera, Curamhuele, Santa Victoria and Valle Morado are non-producing properties as at December 31, 2015.

Oil production in Northern Argentina is trucked to market; therefore, sales of oil in the Noroeste Basin may be seasonally delayed by adverse weather and road conditions, particularly during the months of November through February when the area is subject to periods of heavy rain and flooding. While storage facilities are designed to accommodate ordinary disruptions without curtailing production, delayed sales will delay revenues and may adversely impact our working capital position in Argentina.

Royalties in Argentina are based on a provincial royalty plus an additional provincial turnover tax. The provincial royalty rate is 12% on most of the blocks in Argentina. Under the new National Hydrocarbon law, the Provinces may increase the royalty to 15% for longer-term exploitation/development concessions which enter a ten year exploitation extension period. The provincial turnover tax ranges from 1.5% to 3% on our blocks.

For all of Madalena's blocks in Argentina, upon expiry of the block rights (if concessions are not renegotiated for extension or renewal by way of entering into revised exploration, exploitation/development or evaluation phase type contracts), ownership of producing assets will revert to the provincial governments. For exploitation/development concessions, the Corporation can request a ten to twenty-five year production concession with ten years being the typical extension period on an already existing exploitation contract. To enter into a new exploitation contract or to extend an already existing production contract, this generally involves a combination of a bonus payment and/or a future work commitment. The Corporation enters into formal negotiations and discussions on a regular basis to extend existing exploitation concessions or convert exploration concessions into new exploitation concessions. The Corporation also enters into negotiations or an application and approval process to move certain exploration blocks or concessions from a first exploration period into a second or third exploration period. In addition, exploration blocks focused on unconventional shales or tight sand resources are eligible to enter into evaluation phase type contracts to appraise the unconventional resources. Typical evaluation phase type contracts are in the three to five year range. After evaluation phase contracts are completed, blocks focused on unconventional resources are eligible to enter exploitation/development concessions spanning up to 35 years under the new National Hydrocarbon law.

Rinconada-Puesto Morales Block (100% working interest)

The Corporation acquired its interest in the 31,254 acre block in the Neuquén Basin as part of the GTE Acquisition. The block produces oil and natural gas from the Sierras Blancas and Loma Montosa formations. In the fourth quarter of 2015 production from this block averaged 1,308 BOE/d (42% of Argentina production). Sierras Blancas wells are generally in the advanced stages of decline producing large volumes of fluid at high water cuts. The Corporation continues to optimize the implemented water flood and evaluate and implement projects to stabilize the decline.

Madalena is the operator and holds a 100% working interest pursuant to a ten year exploitation concession based on an agreement with the Province of Rio Negro that has received the requisite government approvals. As part of the terms and conditions of the ten year extension, the Corporation has agreed to capital commitments of $40.3 million on the block over the next ten year period, which includes the drilling of new wells, re-entry activities and contract renewal fees. Capital expenditures in 2015 were approximately $7.8 million which the Corporation expects will qualify towards the total capital commitments of $40.3 million. 2015 expenditures included concession renewal fees and the drilling of one 100% Loma Montosa well. The majority of the remaining commitment of $32.5 million is anticipated to be scheduled over the next four years, including $4.4 million in 2016. The majority of capital spending is expected to be incurred on drilling, completing and equipping the development of the Loma Montosa formation.

El Surubi Block (85% working interest)

The Corporation acquired its interest in the El Surubi Block through the GTE Acquisition in June 2014. Madalena is the operator of the El Surubi Block, which covers 90,824 (77,200 net) acres with the Provincial Company REFSA as the partner. In 2014, just prior to the close of the GTE Acquisition, the PROA-3 well was drilled and placed into production. There are three producing wells on the block which averaged 930 Boe/d in the last quarter of 2015. PROA-2 and PROA-3 are both flowing oil wells and account for 30% of the Corporation's consolidated Argentina production. Madalena has no work obligations on this block.

Coiron Amargo Block (35% working interest)

The Coiron Amargo Block covers an area of approximately 100,000 (35,000 net) acres and is situated approximately 650 miles southwest of Buenos Aires in the Argentine province of Neuquén. The block is divided into two regions called Coiron Amargo Norte (northern portion of the block) and Coiron Amargo Sur (southern portion of the block). Coiron Amargo Norte is currently held under a 25 year exploitation (development) concession which was approved by the Province of Neuquén in 2012 and expires in 2038. All commitments have been fulfilled associated with this portion of the block.

On April 16, 2015, the Corporation received a three year evaluation phase contract from the Province of Neuquén for Coiron Amargo Sur. The Corporation's share of the work commitment is $17.5 million and must be incurred by November 8, 2017. Following this three year evaluation phase contract, Madalena is eligible to enter into a further exploitation (development) concession and/or enter into additional evaluation phase periods to further explore and appraise the Coiron Amargo Sur block.

Madalena and its partners in the Coiron Amargo Sur portion of the 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. For both Coiron Amargo Norte and Coiron Amargo Sur, GyP is responsible for its 10% share of the costs incurred in the development and production phase.

Activity during 2015 included drilling, completing and equipping three (1.1 net) horizontal conventional Sierras Blancas wells and drilling one additional well that was completed and equipped in early 2016.

As of the date of this report, Madalena has seven (2.5 net) horizontal wells on production. In addition, there are several vertical wells which contribute approximately 9% of the production. Five of the existing seven horizontal Sierras Blancas wells have additional net pay which will ultimately be completed for production. Madalena and its partners intend to recomplete two of these wells in 2016 and test the effectiveness of higher volume lift equipment.

The CAS.x-16 Vaca Muerta vertical shale oil well was placed on production prior to the 2014 year end. This Vaca Muerta well produced from a 120 metre open hole section without stimulation (no fracture treatment conducted to date), which is very encouraging given vertical shale wells typically do not flow and produce without fracture treatments. The Corporation and its partners anticipate drilling the first Vaca Muerta horizontal multi-frac well in 2016. The results of a detailed third party review of Geophysical and Geological data on the Coiron Amargo block, combined with knowledge gained after a data exchange for several horizontal multi frac wells directly offsetting Coiron Amargo, will be used to finalize the location and drilling plan. The Corporation anticipates commencing operations in the second half of 2016.

Curamhuele Block (90% working interest)

The Curamhuele Block is operated by Madalena and covers an area of approximately 56,000 (50,400 net) 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.

In September 2013, the second exploration period was extended until November 2014 by the Province of Neuquén. In December 2014, the Province granted an extension to September 2015 to satisfy the remaining work commitments on the block.

In December 2015, Madalena further ratified an extension of its second exploration term with the Province of Neuquén to

September 9, 2016, after which a further extension is available. At December 31, 2015, the remaining work commitment relating to the existing Curamhuele block concession agreement was to complete the Yapai.x-1001 well in the Mulichinco and Lower Agrio shale. Subsequent to the year-end, Madalena fulfilled this remaining work obligation by completing the Yapai.x-1001 well, through the expenditure of approximately $2.8 million. Over a 55 day period, the well has produced 5,338 bbls oil (97 bopd), 7,311 bbls water (133 bbls/d) and 6.1 MMcf gas (110 mcf/d). The well has been flowing up five inch casing and the Corporation is currently evaluating equipping the well with tubing and artificial lift (pumping unit) to optimize production and further test the well's potential.

Madalena expects to convert certain areas of the acreage into an exploitation (development) concession and/or extend the exploration period and/or enter into an unconventional evaluation phase to further appraise the Curamhuele block.

Madalena has posted a performance bond for $17.6 million relating to amounts committed under this exploration permit. The assets of MASA are held as security for the bond. Once the province certifies that Madalena has fulfilled its obligations, the Corporation anticipates that the bond will be cancelled.

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 key zones of interest across the Curamhuele block are the unconventional Vaca Muerta shale, Lower Agrio shale and tight sandstone Mulichinco.

At December 31, 2015, the GLJ Report does not attribute any reserves to Madalena's working interest in the Curamhuele Block.

Cortadera Block (37.8% working interest)

On January 15, 2014, Madalena and its working interest partner signed an amended contract agreement for the extension of the initial exploration period and the definition of subsequent exploration periods.

In 2014, Madalena and its working interest partner satisfied the remaining commitments related to the first exploration period on the block and have the option to enter into a second exploration period extending to October 25, 2018 and potentially a third exploration period extending to October 25, 2021.

Madalena and its partner have submitted an application to the province of Neuquén requesting that the block pass into the second exploration period with the relinquishment of approximately 50% of the block and a commitment to shoot 3D seismic on a portion of the remainder of the block. As of April 21, 2016, Madalena has not received confirmation of approval of this application.

Valle Morado Block (96.6% working interest)

The Corporation acquired its interest in the Valle Morado Block through the GTE Acquisition in June 2014. This block covers 49,099 gross acres and Madalena is the operator. The Valle Morado GTE.St.VMor-2001 well was first drilled in 1989. A previous operator completed a 3-D seismic program over the field and constructed a gas plant and pipeline infrastructure. Production began in 1999 from the GTE.St.VMor-2001 well, but was shut-in in 2001 due to water incursion as a result of downhole mechanical issues at the time. During 2008, a long-term test was performed on the well. The Corporation has no outstanding work obligations on this block. In 2015 there were no significant expenditures and there are none forecasted for 2016. The contract for this block expires in 2034. Even though there is a proven gas structure at Valle Morado, the GLJ Report does not attribute any reserves to Madalena's working interest in the Valle Morado Block and there currently is no production on this block.

Santa Victoria Block (100% working interest)

Madalena acquired its interest in the Santa Victoria Block through the GTE Acquisition in June 2014. This block covers 516,846 gross acres. The Corporation is the operator and has a 100% working interest. The contract is currently in the second of three exploration phases. During the first quarter of 2015, with the second exploration phase expiring in April 2015, the Corporation submitted an application for a three year extension. Negotiations have continued throughout 2015 and are currently ongoing with the Province to reach a multi-year extension agreement.

As at December 31, 2015, the second exploration phase required additional work commitments of $3.75 million, of which no qualifying expenditures had been made.

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, as at December 31, 2015, the Corporation holds approximately 165 gross (approximately 124 net) sections of land (approximately 75% average working interest).

The Corporation has working interests in 85 gross (57.7 net) wells, of which 12 gross (9.3 net) are oil, 21 gross (15.2 net) are gas and 52 gross (33.2 net) are non-producing. Production for the year ended December 31, 2015 averaged 120 bopd of oil, 300 Mcf/d of gas and 9 bbls/d of liquids for total 2015 Canadian average production of 180 BOE/d.

The Corporation's reserve life index in Canada (RLI) is 31 years based on proved plus probable reserves of approximately 2,230 MMboe. As of February 8, 2016, Madalena has entered into a Proposed Transaction concerning non-core assets located in the Greater Paddle River area. See *"General Development of the Business - Recent Developments*".

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, 2015:

	Oil Wells		**Natural Gas Wells**		**Non-producing Wells**		**Total**	
Location	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Argentina	125.0	88.2	20.0	18.5	71.0	54.4	216.0	161.1
Canada	12.0	9.3	20.0	14.2	53.0	34.1	85.0	57.6
	137.0	97.5	40.0	32.7	124.0	88.5	301.0	218.7

Properties with No Attributed Reserves

The following table sets forth Madalena's land position as at December 31, 2015:

	Gross		**Net**	
Location	**Acres**	**Sections**	**Acres**	**Sections**
Argentina, South America	1,235,223	n/a	946,652	n/a
Alberta, Canada	71,853	112	61,248	96

In Argentina the Corporation does not separate out the portion of a block that is undeveloped. As of the date of this report, Madalena has four blocks in Argentina with no attributable reserves totalling 745,298 Gross Acres or 661,386 Net Acres. In 2016 the Corporation expects to relinquish approximately 23,289 Net Acres being a portion of a block.

The remaining work commitments relating to the Corporation's concessions in Argentina are described under "*Other Oil and Gas Information - Principal Properties – Argentina*."

In Canada, Madalena expects 29,927 gross (29,927 net) non-core acres to expire in 2016.

Forward Contracts and Marketing

As of the date hereof, the Corporation has no physical or financial commodity contracts in place.

Tax Horizon

Argentina

In Argentina, Madalena has four operating entities – three of which were acquired pursuant to the Acquisition. Two of the three entities acquired incur income taxes. The income tax rate in Argentina is 35%. The two entities that are not subject to income tax are subject to minimum taxes, which are generally taxed at 1% of net assets. Current income tax expense (including minimum tax) for the year ended December 31, 2015 was $5.4 million (2014 - $2.8 million (CAD $3.1 million)).

Canada

As at December 31, 2015, the Corporation has, subject to confirmation by income tax authorities, cumulative income tax deductions of approximately CAD $91 million (2014 – CAD $91 million). Accordingly, the Corporation does not anticipate being taxable in the foreseeable future.

Capital Expenditures

The following table summarizes capital expenditures (net of asset retirement costs, and capitalized stock based compensation) related to the Corporation's activities for the year ended December 31, 2015. The Corporation did not make any property acquisitions in 2015.

	Argentina $USD MM	Canada $USD MM	Total $USD MM
Exploration costs	8.5	-	8.5
Development costs	32.4	0.5	32.9
Total	40.9	0.5	41.4

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, 2015:

CANADA

	Exploratory Wells		Development Wells	
	Gross	**Net**	**Gross**	**Net**
Natural gas	-	-	-	-
Dry	-	-	-	-
Total	-	-	-	-

ARGENTINA

	Exploratory Wells		Development Wells	
	Gross	**Net**	**Gross**	**Net**
Light and Medium Oil	1.0	1.0	4.0	2.05
Total	1.0	1.0	4.0	2.05

Production Estimates

The following table sets out the volume of the Corporation's gross working interest production estimated for the year ended December 31, 2016 as evaluated by the Reserve Engineers which is reflected in the estimate of future net revenue disclosed in the tables contained under "*Report on reserves data by independent qualified reserves evaluator or auditor*".

	Light and Medium Oil *(bopd)*	Tight Oil *(bopd)*	Natural Gas *(Mcf/d)*	Natural Gas Liquids *(bbls/d)*	BOE *(BOE/d)*
Total Proved					
Argentina	2,439	-	2,137	34	2,829
Canada	161	-	1,034	43	376
	2,600	-	3,171	77	3,205
Total Probable					
Argentina	294	94	400	3	457
Canada	86	-	1,079	41	308
	380	94	1,479	44	765
Total Proved Plus Probable					
Argentina	2,733	94	2,537	37	3,286
Canada	247	-	2,113	84	684
	2,980	94	4,650	121	3,970

Production History

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

ARGENTINA

USD	Q4 2015	Q3 2015	Q2 2015	Q1 2015
Average Daily Sales Volumes				
Light and medium oil – bopd[1]	2,549	2,706	3,092	2,653
Conventional Natural gas – Mcf/d	3,363	3,843	4,455	3,895
Combined (BOE/d)	3,110	3,346	3,834	3,302
Average Price Received				
Light and medium oil – $/bbl	70.65	75.43	78.36	72.86
Conventional Natural gas – $/Mcf	4.31	5.54	5.11	4.27
Combined ($/BOE)	62.58	67.36	69.11	63.58
Royalties Paid				
Light and medium oil – $/bbl	10.82	10.72	10.90	10.00
Conventional Natural gas – $/Mcf	0.74	1.03	4.27	0.65
Combined ($/BOE)	9.67	9.85	13.76	8.80
Operating Costs				
Light and medium oil – $/bbl	30.25	28.66	25.43	25.14
Conventional Natural gas – $/Mcf	4.65	4.37	3.83	3.93
Combined ($/BOE)	29.83	28.19	24.95	24.83
Netback Received – ($/BOE)	23.06	29.58	30.41	29.94

Notes
(1) Includes natural gas liquids

CANADA

USD	Q4 2015	Q3 2015	Q2 2015	Q1 2015
Average Daily Sales Volumes				
Light and medium oil – bopd[1]	122	119	132	148
Conventional Natural gas – Mcf/d	251	-	143	816
Combined (BOE/d)	164	119	156	284
Average Price Received				
Light and medium oil – $/bbl	31.92	35.10	46.33	28.90
Conventional Natural gas – $/Mcf	1.85	2.45	1.73	2.26
Combined ($/BOE)	26.61	35.09	39.64	21.57
Royalties Paid				
Light and medium oil – $/bbl	9.66	5.79	8.29	3.35
Conventional Natural gas – $/Mcf[2]	0.35	1.06	5.71	0.58
Combined ($/BOE)	7.85	5.84	13.36	2.43
Operating Costs				
Light and medium oil – $/bbl	34.94	36.02	48.04	28.76
Conventional Natural gas – $/Mcf	6.25	27.90	20.93	5.26
Combined ($/BOE)	35.55	47.69	63.16	29.70
Netback Received – ($/BOE)	(16.79)	(18.43)	(33.92)	(10.55)

Notes
(1) Includes natural gas liquids

Sales Volume by Field

The following table discloses for each important field, and in total, as a percentage of the Corporation's sales volumes for the financial year ended December 31, 2015 for each product type.

Field	Light and Medium Crude Oil and NGL (bbls/d) [1]	Natural Gas (Mcf/d)	BOE (BOE/D)	% (Corporation's consolidated production)
Canada				
Greater Paddle River	130	300	180	5%
Argentina				
Puesto Morales	941	3,385	1,505	42%
El Surubi	962	-	962	27%
Coiron Amargo	364	502	448	13%
Other minor	482	-	482	13%
	2,749	3,887	3,397	95%
Total	**2,879**	**4,187**	**3,577**	**100%**

Notes
(1) NGLs are less than 3% of the total liquid volume

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 21, 2016, there were 542.1 million Common Shares issued and outstanding. In addition, as at such date, there were an aggregate of 37.9 million 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 OTCQX 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, 2015 and the first quarter of 2016:

Period	High ($)	Low ($)	Volume
2015			
January	0.26	0.21	21,294,767
February	0.35	0.22	29,149,002
March	0.43	0.30	26,287,690
April	0.43	0.32	18,252,734
May	0.42	0.33	15,934,894
June	0.43	0.39	9,636,829
July	0.40	0.31	11,383,940
August	0.37	0.23	7,094,869
September	0.36	0.29	11,373,027
October	0.35	0.30	7,720,895
November	0.37	0.32	6,039,571
December	0.35	0.27	9,338,216
2016			
January	0.30	0.21	20,330,414
February	0.29	0.25	5,836,226
March	0.27	0.21	20,041,061

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, 2015 and in the 2016 year to date:

Date	Securities(1)	Number of Securities	Price per Security
March 13, 2015	Common Shares upon exercise of stock options (3)	533,333	$0.29
April 16, 2015	Common Shares upon exercise of stock options (3)	250,000	$0.35
May 22, 2015	Common Shares upon exercise of stock options (3)	400,000	$0.29
May 22, 2015	Common Shares upon exercise of stock options (3)	66,666	$0.35
August 31, 2015	Issuance of stock options to directors, officers and employees (2)	15,563,158	$0.30
September 3, 2015	Common Shares issued upon exercise of stock options (3)	800,000	$0.21
September 9, 2015	Common Shares issued upon exercise of stock options (3)	150,000	$0.21
September 10, 2015	Common Shares issued upon exercise of stock options (3)	100,000	$0.21
January 12, 2016	Issuance of stock options to directors, officers and employees (2)	8,650,000	$0.27

Notes:

(1) As of April 21, 2016, 37.9 million options issued pursuant to the Corporation's stock option plan were outstanding at exercise prices between CAD $0.27 and CAD $0.69.

(2) Reflects the exercise price of the options granted

(3) Reflects the exercise price of such options

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[(4)]	Principal Occupation for the Previous 5 Years
Steven Sharpe Toronto, Canada Director and Chairman of the Board of Directors, Interim President and Chief Executive Officer[(1)(2)(5)]	September 23, 2014	Currently Managing Director of The EmBeSa Corporation, a private consultancy dealing primarily with corporate restructuring and business strategy. Previously, Mr. Sharpe was Chairman of Longview Oil Corp. from April 2010 and Interim CEO from February 2014 until its acquisition by Surge Energy in June 2014, a director of Advantage from 2001 and Non-Executive Chairman from 2005 until February 2014, a director and Chair of the Special Committee of the Board of Renegade Petroleum Ltd. from March 2013-January 2014 and a director and CEO of C.A. Bancorp. Inc. until March 2013. From October 2009 to March 2010, Mr. Sharpe was Chairman and Chief Executive Officer of Prime Restaurants Royalty Income Fund. Until July 2009, he was Senior Advisor to Blair Franklin Capital Partners, Inc., a Toronto-based investment bank which he co-founded in May 2003. Prior to that, Mr. Sharpe was Managing Partner of Blair Franklin, from its inception. Before then, he was Managing Director of The EBS Corporation, a management and strategic consulting firm. Prior to EBS, Mr. Sharpe was Executive Vice President of the Kroll-O'Gara Company ("Kroll"), New York. He was a partner with Davies, Ward & Beck in Toronto until 1998. Mr. Sharpe is a lawyer by training, graduating from Osgoode Hall Law School in 1977.
Barry B. Larson Alberta, Canada Director [(3)]	July 21, 2010	Mr. Larson was Vice President Operations and Chief Operating Officer of Parex Resources Inc. from September, 2009 to December, 2015. Prior thereto, Vice President Operations and Chief Operating Officer of Petro Andina Resources Inc. from February, 2005 to September, 2009.
Eric Mark New York, United States Director	March 23, 2016	Mr. Mark, an independent director, is currently a Managing Director at Batuta Capital Advisors ("Batuta"), a merchant bank targeting middle market and special situation opportunities in both the public and private markets. Prior to joining Batuta, Mr. Mark was a Senior Analyst/Junior Portfolio Manager at BTG Pactual ("BTG"), a Brazilian investment bank, co-managing a $2 billion portfolio of distressed, high yield and special situation equities. Mr. Mark has over 20 years of investment experience (credit and equity) in the energy, metals & mining, general industrials and telecommunications sectors across North America, South America and Europe. .
Gus Halas California, United States[(1)(2)] Director	January 22, 2015	Mr. Halas is currently a director of Triangle Petroleum Corporation (NYSE MKT:TPLM), Optimize RX, Hooper Holmes and School Speciality Inc. and has significant experience in the energy industry and in public companies in both an executive and board role, including his roles as President, Chief Executive Officer, Director and/or Chairman of Central Garden & Pet Company, T-3 Energy Services, Inc., Clore Automotive, Marley Cooling Tower, Ingersoll Dressers Pump Services Group and Aquilex Corporation. Mr. Halas has also held a leadership position at Sulzer Industries, Inc. and is currently a Member of the Advisory Board of White Deer Energy, a Houston based private equity firm. Mr. Halas received a BS in both Physics and Economics at Virginia Tech.
Jay Reid Alberta, Canada Director [(2)]	May 26, 2015	Partner at the Calgary based law firm of Burnet, Duckworth & Palmer LLP and has practiced corporate and securities law since 1990. Corporate Secretary of Advantage Oil & Gas Ltd. (NYSE and TSX) and various private issuers
Keith Macdonald Alberta, Canada Director [(1)(2)]	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. from March, 2011 to January 2015.
Ray Smith Alberta, Canada Director and Chairman of the Board of Directors [(3)]	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,

Name, Address and Position	Director Since[(4)]	Principal Occupation for the Previous 5 Years
		2005 to November, 2007.
Ving Woo Alberta, Canada Director [(3)]	March 10, 2006	Vice-President and Chief Operating Officer of Bellatrix Exploration Ltd., from October 2010 to September 2014; 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.
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.
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.
Stephen Kapusta Alberta, Canada Vice President, Engineering	N/A	Vice President, Engineering of Madalena since August 2015, he previously served as Madalena's Head of Engineering from December 1, 2014 and prior to that as a mergers and acquisitions advisor. Previously, Mr. Kapusta was President and Chief Executive Officer of Canext Energy Ltd. and its predecessor Canex Energy Inc. from May 2002 to April 2010. He was a Director of Canext Energy Ltd. from June 2006 to April 2010. Prior thereto he was a Director of Canex Energy Inc. from May 2002 to June 2006. In addition, he also served as a Director of Trimox Energy Inc. from September 2004 to June 2007. Mr Kapusta was Vice President of Resource Development and Marketing at Star Oil and Gas Ltd. from 1993 to 2001.
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.

Notes:
(1) Member of the Audit Committee.
(2) Member of the Corporate Governance and Compensation Committee.
(3) Member of the Reserves Committee.
(4) 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.
(5) As announced on March 24, 2016, Mr. Steven Sharpe, Chairman of the Board, was appointed Interim President and Chief Executive Officer of the Corporation following the departure of Mr. Kevin Shaw, the Corporation's former President, Chief Executive Officer and director.

The directors and officers of the Corporation as a group own, directly or indirectly, or control or exercise direction over 9.0 million Common Shares, representing 1.66% of the issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Other than as set out below, to the knowledge of the Corporation, no director or executive officer of the Corporation: (i) is, or has been in the last ten 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 ten 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.

Other than as set out below, 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.

On October 14, 2011, the Alberta Securities Commission (the "**ASC**") issued a decision imposing sanction and costs orders against Stephen Kapusta, the current Vice-President, of Engineering of Corporation (the "**Decision**"), who was found by the ASC to have engaged in illegal insider trading of shares of Canext Energy Ltd while acting as its president and chief executive officer. The sanction orders made in the Decision included a three-year prohibition on trading in or purchasing securities or exchange contracts and on acting as a director or officer (apart from an exception for family-owned non-reporting issuers), a $228,000 administrative penalty and costs of $16,500.

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 of the date of this AIF, there are no 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 2015 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 2015 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.

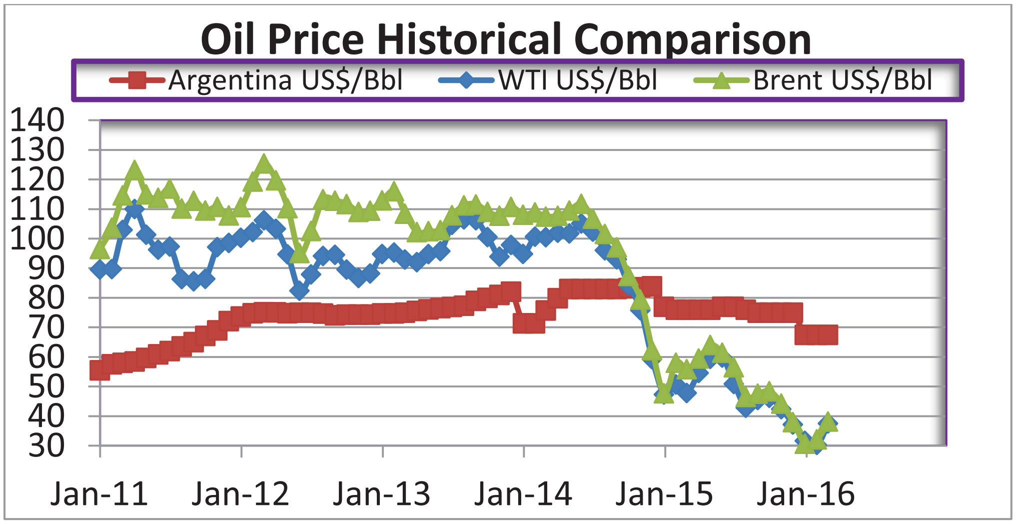
INDUSTRY CONDITIONS

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

Argentina is a net importer of oil. The government of Argentina sets the benchmark (Medanito) price for oil. Regulators in Argentina have advised that the Medanito oil price posting for 2016, is expected to be set at USD 67.50/bbl. Although currently Argentina prices are a premium to Brent pricing, there can be no certainty that prices in Argentina will not be adjusted further within the year. The chart below shows the historical relationship between Medanito, WTI and Brent prices.



On November 25, 2008, the government of Argentina issued decree No. 2014/2008, which introduced the Petroleo Plus Program commonly referred to as Oil Plus ("**Oil Plus**"). The stated policy intent of the Oil Plus program was to increase oil reserves and grow oil production in Argentina. Under the Oil Plus program, oil producers were able to earn fiscal credits that could be applied against export taxes on oil and other petroleum products. There were two components to the Oil Plus program, each calculated and awarded separately on different performance-based criteria: (1) production growth; and (2) replacement of total proved reserves. In the Argentine government's presentation of the Oil Plus program, it was specified that qualifying producers could use the credits directly against export taxes or trade them to third party exporters, such as refiners, at face value. The fiscal credits were to be fully taxable but not subject to provincial royalties.

On July 13, 2015, the government terminated the Petroleo Plus program effective December 31, 2014 and granted eligible companies the right to receive Argentina issued government bonds as full settlement of any outstanding export tax incentive credits, subject to certain conditions.

On February 2, 2015 the Government of Argentina announced a new oil incentive program, effective January 1, 2015. This new program was effective for all of 2015 but was not extended beyond 2015. To stimulate production, the Government of Argentina established a $3.00 per barrel royalty free bonus payment to be paid on all oil production for each company that increases its oil production or maintains it at greater than 95% of Q4-2014 volumes. This $3.00 per barrel incentive was incremental to the regulated oil price per barrel received in Argentina’s domestic oil market.

Gas prices in Argentina are subject to seasonal demand and are negotiated between the producer and the buyer. Summer prices have been set at $4.20/mmbtu for the period October 2015 to April 2016. For the period May to September 2016, which is the Argentine winter, the price has yet to be published. Winter prices in 2015were $5.30/mmbtu.

The Argentina government has introduced an incentive price of USD $7.50/MMbtu for companies that add incremental supply of natural gas. Currently, Madalena does not have any production that qualifies. If the Corporation is successful with new gas discoveries it may be eligible for the incentive price.

New Government

On November 22, 2015, Mauricio Macri, the former mayor of Buenos Aires, won the presidential runoff and was sworn in as President of Argentina on December 10, 2015. Although Mr. Macri ran on a platform that included revitalizing Argentina's economy by implementing free market reforms and improving foreign relations to, among other things, attract foreign investment and gain access to international credit markets, the Corporation is unable to predict with certainty what, if any, reforms the new government will be able to implement and/or maintain.

Mr. Macri appointed Juan Jose Aranguren, the former Chief Executive Officer of Shell´s Argentine branch, as Minister of Energy and Mines.

Consistent with the government's campaign platform, currency controls were relaxed in December 2015 and the ARS underwent a devaluation, reflecting its purchasing power in the global economy. A portion of the Corporation's operating costs and general and administrative expenses incurred in Argentina are denominated in ARS. As a result, the Corporation's operating costs per BOE and general and administrative expenses are expected to decrease in USD equivalent terms.

The newly elected government has also reached tentative agreements with hold-out creditors who had refused to restructure certain of Argentina's bond debt after Argentina defaulted on the debt in 2001. In order to regain access to international capital markets, Argentina's congress must approve the agreements and lift certain laws, which prevented Argentina from paying creditors who had rejected settlement offers in 2005 and 2010. If the bond crisis is resolved, Argentina is expected to regain access to international capital markets. Subsequent to year end Congress has approved the agreements until such time as the ARS costs increase, as a result of anticipated inflationary pressure.

It is anticipated that the Macri government will work to improve the current business climate in order to encourage investment and increase transparency. Management also expects that the Macri government will implement a plan to gradually deregulate domestic energy pricing. The timing of such changes is currently unknown. These expected measures plus others yet to be announced will be evaluated by the Corporation within the context of the government's new economic program to assess the impact on the energy industry and Madalena.

For a description of the prices and netbacks achieved by the Corporation during the year ended December 31, 2015, see *"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 workover 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 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 5 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 point five and three percent of gross revenue less certain deductions. A value added tax ("**VAT**") at a rate of 21 percent is added 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 in Argentina pay either income tax at a rate of thirty-five (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.

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. 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 twelve (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.

On October 31, 2014 Argentina amended its NH Law to create incentives for foreign investment and to boost the country's conventional and unconventional hydrocarbons exploration and production (the "**Hydrocarbons Reform Law**"). The Hydrocarbons Reform Law implements substantial changes to the previous regime. Some of those changes are highlighted below:

1. Amendment to Section 27 of the NH Law and incorporation of new articles in order to grant title holders the right to request an "Unconventional Exploitation Concession" that shall have a term of 35 years (versus the 25 year period granted under prior regime to regular exploitation concessions). Unconventional exploitation is defined by Law 27007 as the extraction of hydrocarbons using unconventional stimulation techniques applied in geological formations of shale gas, shale oil, tight sands, tight gas, tight oil, coal bed methane or geological formations characterized by low permeability rocks.
2. In all cases, 10-year extension periods are provided in favour of the concessionaires. The prior regime granted only one extension period, while Law 27007 allows for several extension periods to be granted in addition to the original concession extension period. Extensions are provided even in instances where the concession was already extended.
3. Provinces are allowed to request an "extension bonus payment", equal to the amount resulting from multiplying proved reserves remaining at the end of the concession term by 2% of the basin average price during the previous two years.
4. Amendment to Section 23 of the NH Law to set new maximum exploration period terms as follows:
    a. Conventional target exploration:
    1st Period up to 3 years; 2nd Period up to 3 years; (previously 4); Extension phase up to 5 years.
    b. Unconventional target exploration or off-shore exploration:
    1st Period up to 4 years; 2nd Period up to 4 years; Extension phase up to 5 years.
5. Amendment to Section 26 of the Hydrocarbons Law, which allows the owner of an exploration permit, who opts to access to the 2nd exploration period, to keep 100% of the surface. The prior regime required relinquishment of 50% of the

surface when moving to the following exploration period. In case of exercise of the extension phase, the owner would have to relinquish up 50% of the surface. The bill considers the extension phase as an option granted in favor of the companies.

6. Standardizes certain aspects of hydrocarbons regulation across the provinces, preventing the establishment of different surface fees, royalties, or procedures. Specifically, it: (i) establishes the exploration permits and exploitation concessions surface fee; (ii) determines that production concessionaires must pay a 12% royalty for the first term of the concession, and up to an 18% royalty in the following extensions; (iii) allow the federal and provincial executives to reduce royalties down to 25% of the applicable royalty to promote unconventional production; and (iv) establishes a unified competitive bidding procedure that the federal government and the provinces must follow when awarding exploration permits and exploitation concessions.
7. Restricts the federal government and the provinces of Argentina from assigning new areas to national or provincial oil companies, and mandates those companies to associate with third parties for the effective exploration or exploitation of the areas currently under their control.
8. Establishes additional contributions to be paid to hydrocarbon-producing provinces by private companies for Corporate Social Responsibility (amounting to 2.5% of the initial investment), and by the federal government to finance local infrastructure projects (the amount is to be determined later).
9. Amendments to Sections 25 and 34 of the NH Law, which eliminate restrictions prohibiting a single entity to hold more than five permits and concessions.
10. Lowers the limit of foreign investments to USD 250 million over a three year period in a project (to be approved by the Federal Commission) prior to benefiting from the Investment Promotion Regime established by Decree 929/13. The portion of hydrocarbons subject to the benefits of the Investment Promotion Regime would be of 20% for onshore exploitation and 60% of offshore exploitation. This allows qualifying companies to export oil up to 20% of production without export duties.
11. Import benefits: Special equipment and machinery may be imported at reduced or zero rates.

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. Commitments may be expressed in work units with each activity equating to a different number of units. 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 ten 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.

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 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

On December 12, 2015, the United Nations Framework Convention on Climate Change (the "**UNFCCC**") adopted the Paris Agreement, to which Argentina is a participant. The Paris Agreement mandates that all countries must work together to limit global temperature rise resulting from GHG emissions to a goal of less than 2° Celsius and to pursue efforts to limit below 1.5° Celsius, through implementing successive nationally determined contributions. Technical details remain unreleased.

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 Argentine 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, which results in the market determining 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, production targets of the OPEC, 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 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 license from the NEB. The NEB is currently undergoing a consultation process to update the regulations governing the issuance of export licenses. The updating process is necessary to meet the criteria set out in the federal Jobs, Growth and Long-term Prosperity Act (Canada) (the "**Prosperity Act**") which received Royal Assent on June 29, 2012. 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 (Canada).

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, Intercontinental Exchange or the New York Mercantile Exchange 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 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 m3/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 40 years) or for a larger quantity requires an exporter to obtain an export license 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.

Trans-Pacific Partnership

On October 5, 2015, Canada and 11 other countries announced an agreement in respect of the Trans-Pacific Partnership ("**TPP**"). Canada and each participating country must also ratify the TPP in their national legislatures. The TPP is the most ambitious trade initiative in the Asia-Pacific region. The TPP would lower tariffs on a wide range of Canadian products and benefit exporters across Canada in a number of sectors, including agriculture, wood and wood products, chemicals and plastics, and fish and seafood. An agreement would also bring enhanced and more predictable market access for Canada's services providers.

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 oil sands projects, 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.

The Federal Government has signaled it will, among other things, phase out subsidies for the oil and gas industry, which include only allowing the use of the Canadian Exploration Expenses tax deduction in cases of successful exploration, implementing more stringent reviews for pipelines, and establishing a pan-Canadian framework for combating climate change. These changes could affect earnings of companies operating in the oil and natural gas industry.

Alberta

On January 29, 2016, the Government of Alberta released and accepted the Royalty Review Advisory Panel's recommendations, which outlined the implementation of a "Modernized Royalty Framework" for Alberta (the "**MRF**"). The MRF will take effect on January 1, 2017. Wells drilled prior to January 1, 2017 will continue to be governed by the current "Alberta Royalty Framework" for a period of ten years until January 1, 2027. The MRF is structured in three phases: (i) Pre-Payout, (ii) Mid-Life, and (iii) Mature. During the Pre-Payout phase, a fixed 5% royalty will apply until the well reaches payout. Well payout occurs when the cumulative revenue from a well is equal to the Drilling and Completion Cost Allowance (determined by a formula that approximates drilling and completion costs for wells based on depth, length and historical costs). The new royalty rate will be payable on gross revenue generated from all production streams (oil, gas, and natural gas liquids), eliminating the need to label a well as "oil" or "gas". Post-payout, the Mid-Life phase will apply a higher royalty rate than the Pre-Payout phase. While the metrics for calculating the Mid-Life phase royalty have yet to be released, the rate will be determined based on commodity prices and are intended, on average, to yield the same internal rate of return as under the current Alberta Royalty Framework. In the Mature phase, once a well reaches the tail end of its cycle and production falls below a Maturity Threshold, currently estimated to be 20 bbl/d for oil and 200 mcf/d for gas, the royalty rate will move to a sliding scale (based on volume and price) with a minimum royalty rate of 5%. The downward adjustment of the royalty rate in the Mature phase is intended to account for the higher per-unit fixed cost involved in operating an older well. Details of the MRF, including the applicable royalty rates and formulas, are scheduled to be released by April 21, 2016.

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

Royalties, for wells drilled prior to January 1, 2017 are paid pursuant to "The New Royalty Framework" (implemented by the Mines and Minerals (New Royalty Framework) Amendment Act, 2008) and the "Alberta Royalty Framework" until January 1, 2027. 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 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 up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and
- Horizontal oil wells 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.

While the MRF eliminates the various royalty credits and incentives, outlined above, for wells drilled after December 31, 2016, the Government of Alberta has committed to creating cost allowance programs for both enhanced oil recovery schemes and higher risk experimental drilling. Details of these programs are scheduled to be released simultaneously with the finalization of the MRF.

Land Tenure

The respective provincial governments predominantly own the rights to crude oil and natural gas located in the western provinces. Provincial governments 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 issued after to January 1, 2009 at the conclusion of the primary term of the lease or license.

Production and Operation Regulations

The oil and natural gas industry in Canada is highly regulated and subject to significant control by provincial regulators. Regulatory approval is required for, among other things, the drilling of oil and natural gas wells, construction and operation of facilities, the storage, injection and disposal of substances and the abandonment and reclamation of well-sites. In order to conduct oil and gas operations and remain in good standing with the applicable provincial regulator, Madalena must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance with such legislation, regulations, orders, directives or other directions can be costly and a breach of the same may result in fines or other sanctions.

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 to 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, 2012. 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 Alberta Energy Regulator (the "**AER**") is the single regulator responsible for all energy development in Alberta. The AER ensures the safe, efficient, orderly, and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment. 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 single regulator is 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.

The Government of Alberta relies on regional planning to accomplish its responsible resource development goals. The following frameworks, plans and policies form the basis of Alberta's Integrated Resource Management System ("**IRMS**"). The IRMS method to natural resource management sets out to engage and consult with stakeholders and the public. While the AER is the primary regulator for energy development, several governmental departments and agencies may be involved in land use issues, including Alberta Environment and Parks, Alberta Energy, the AER, the Alberta Environmental Monitoring, Evaluation and Reporting Agency, the Policy Management Office, the Aboriginal Consultation Office, and the Land Use Secretariat.

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 northeastern corner of Alberta that is approximately 93,212 square kilometres in size. The region includes a substantial portion of the Athabasca oil sands area, which contains approximately 82% of the province's oil sands resources and much of the Cold Lake oil sands 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, oil sands companies' tenure has been (or will be) cancelled in conservation areas and no new oil sands 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.

In July 2014, the Government of Alberta approved the South Saskatchewan Regional Plan ("**SSRP**") which came into force on September 1, 2014. The SSRP is the second regional plan developed under the ALUF. The SSRP covers approximately 83,764 square kilometres and includes 44% of the provincial population.

The SSRP creates four new and four expanded conservation areas, and two new and six expanded provincial parks and recreational areas. Similar to LARP, the SSRP will honour existing petroleum and natural gas tenure in conservation and provincial recreational areas. However, any new petroleum and natural gas tenures sold in conservation areas, provincial parks, and recreational areas will prohibit surface access. However, oil and gas companies must minimize impacts of activities on the natural landscape, historic resources, wildlife, fish and vegetation when exploring, developing and extracting the resources. Freehold mineral rights will not be subject to this restriction.

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 Alberta Oil & Gas Conservation Act 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.

Made effective in three phases, from May 1, 2013 to August 1, 2015, the AER implemented important changes to the AB LLR Program (the "**Changes**") that resulted in a significant increase in the number of oil and gas companies in Alberta that are required to post security. The Changes affect the deemed parameters and costs used in the formula that calculates the ratio of deemed liabilities to deemed assets under the AB LLR Program, increasing a licensee's deemed liabilities and rendering in the industry average netback factor more sensitive to asset value fluctuations. The Changes stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

The AER implemented the inactive well compliance program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under Directive *013: Suspension Requirements for Wells* ("**Directive 013**"). The IWCP applies to all inactive wells that are noncompliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within 5 years. As of April 1, 2015, each licensee is required to bring 20% of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with *Directive 020: Well Abandonment*. The list of current wells subject to the IWCP is available on the AER's Digital Data Submission system.

Climate Change Regulation

Federal

Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulatory environment of the oil and natural gas industry in Canada. Such regulations, surveyed below, impose certain costs and risks on the industry.

The Government of Canada is a signatory to 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 United States-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.

On December 12, 2015, the UNFCCC adopted the Paris Agreement, to which Canada is a participant. The Paris Agreement mandates that all countries must work together to limit global temperature rise resulting from GHG emissions to a goal of less than 2° Celsius and to pursue efforts to limit below 1.5° Celsius, through implementing successive nationally determined contributions. Technical details remain unreleased, but the Government of Canada is expected to announce its recommendations for a climate change framework in October 2016, which will significantly increase Canada's GHG emission reduction targets.

Alberta

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 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 is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their GHG emissions. The SGER applies to facilities emitting more than 100,000 tonnes of GHGs in 2003 or any subsequent year (the "**Regulated Emitters**"), 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.

On June 25, 2015, the Government of Alberta renewed the SGER for a period of two years with significant amendments while Alberta's newly formed Climate Advisory Panel conducted a comprehensive review of the province's climate change policy. In 2015, Regulated Emitters are required to reduce their emissions intensity by 2% from their 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, 10% of their baseline in the eighth year and 12% of their baseline in the ninth or subsequent years. These reduction targets will increase, meaning that Regulated Emitters in their ninth or subsequent years of commercial operation must reduce their emissions intensity from their baseline by 15% in 2016 and 20% in 2017.

Regulated Emitters can meet their emissions intensity targets through a combination of the following: (1) producing its products with lower carbon inputs, (2) purchasing emissions offset credits from non-regulated emitters (generated through activities that result in emissions reductions in accordance with established protocols), (3) purchasing emissions performance credits from other Regulated Emitters that earned credits through the reduction of their emissions below the 100,000 tonne threshold, (4) cogeneration compliance adjustments, and (5) by contributing to the Climate Change and Emissions Management Fund (the "**Fund**"). Contributions to the Fund are made at a rate of $15 per tonne of GHG emissions, increasing to a rate of $20 per tonne of GHG emissions in 2016 and $30 per tonne of GHG emissions in 2017. Proceeds from the Fund are directed at testing and implementing new technologies for greening energy production.

On November 22, 2015, as a result of the Climate Advisory Panel's Climate Leadership report, the Government of Alberta announced its Climate Leadership Plan which proposes to introduce a carbon tax on all emitters. An economy-wide levy $30 per tonne of GHG emissions will be phased in, starting in January 2017 at $20 per tonne, and increasing to $30 per tonne in January 2018. An oil sands specific approach was proposed to replace the $30 per tonne of GHG emissions to further reduce emissions and promote carbon competitiveness rather than rewarding past intensity levels. A 100 megatonne per year limit for GHG emissions was proposed for oil sands operations, which currently emit roughly 70 megatonnes per year. This cap exempts new upgrading and cogeneration facilities, which are allocated a separate ten megatonne limit. The existing SGER will be replaced for large industrial facilities with a Carbon Competitiveness Regulation ("**CCR**"), in which sector specific output-based carbon allocations will be used to ensure competitiveness.

Alberta is also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed $1.24 billion over 15 years to fund two large-scale carbon capture and storage 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 Argentine Operations

The majority 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 Argentine 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.

In November 2012, the Argentine 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 or is in the process of meeting all of its investment commitments to date with respect to its participation in its blocks in the four provinces in Argentina in which it operates, any future changes to the licensing regimes in these provinces 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 S.A. The Corporation is subject to certain political, economic, and other uncertainties related to the nationalization of Repsol YPF S.A., 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.

On November 22, 2015, Mauricio Macri, the former mayor of Buenos Aires, won the presidential runoff and was sworn in as President of Argentina on December 10, 2015. Although Mr. Macri ran on a platform that included revitalizing Argentina's economy by implementing free market reforms and improving foreign relations to, among other things, attract foreign investment and gain access to international credit markets, the Corporation is unable to predict with certainty what, if any, reforms the new government will be able to implement and/or maintain.

Economic and Political Developments in Argentina, Including Export Controls

The recently elected President of Argentina goal is to revitalize Argentina's economy by implementing free market reforms and improving foreign relations to, among other things, attract foreign investment and gain access to international credit markets. Consistent with the government's campaign platform, currency controls were relaxed in December 2015 and the ARS underwent a devaluation, reflecting its purchasing power in the global economy.

The Corporation is unable to predict with certainty what, if any, reforms the new government will be able to implement or how successful those reforms will be.

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 are currently higher than those received in North America. There is no certainty that the current oil and gas prices in Argentina will remain above current world prices.

Fluctuations in Foreign Currency Exchange Rates

Crude oil sales in Argentina are denominated in USD but collected in ARS, natural gas sales are denominated in ARS and operating and capital costs are generally incurred in ARS and USD. Fluctuations in the USD, ARS 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. 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 USD 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 licenses, license applications or other legal arrangements will not be adversely affected by changes in governments or in the actions of government authorities or others, or the effectiveness and enforcement of such arrangements.

General Risk Factors

Going Concern

The Corporation's business is capital intensive and additional capital is required on a periodic basis. Specifically, continuing operations, as intended, are dependent on management’s ability to raise required funding through future equity issuances, credit facilities, asset sales or a combination thereof, which is not assured, especially in the current uncertain financial and commodity price environment. The sharp decline in commodity prices during the latter half of 2014 through to the year-ended December 31, 2015 negatively affected the Corporation's ability to access additional capital on terms acceptable to the Corporation, which is required for liquidity purposes and to fund commitments on the Corporation's blocks in Argentina. This, despite the fact, in 2015, particular emphasis was placed on accessing debt financing and in early 2016 emphasis was also placed on equity financing. See "*Recent Developments*". The current world-wide economic environment relating to the oil and gas industry has made access to capital challenging for many companies, Madalena included. This has resulted in liquidity challenges and unless the Corporation is able to raise additional capital or renegotiate its commitments, it does not anticipate meeting all of its anticipated 2016 and 2017 capital commitments. Furthermore, there is potential that future commodity prices and the world-wide economic environment relating to the oil and gas industry, in general, will remain relatively stagnate in its current position for an extended period of time and Madalena will need to negotiate with its creditors and/or Argentine work commitment partners to improve payment terms and/or pursue some form of asset sale, debt restricting, equity financing or other capital raising effort in order to fund its operations and to service its existing debt during the next twelve months. To that end, the Corporation is currently, and will continue, on an ongoing basis, examining alternative sources of capital, including potential debt and equity financing and ways to monetize its assets, including, without limitation, asset sales or swaps, joint ventures or other transactions with industry partners, all with a view to enhance liquidity and meet commitments. The need to raise capital or defer expenditures to fund ongoing operations creates uncertainty that may cast doubt over the Corporation's ability to continue as a going concern. While the Corporation believes that these actions will mitigate the adverse conditions that Madalena, like all oil and gas participants, is facing, there is no certainty that these and other strategies will be sufficient to permit the Corporation to continue as a going concern.

The need to raise capital to fund ongoing operations creates a material uncertainty that may cast significant doubt over the Corporation's ability to continue as a going concern.

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. As at December 31, 2015 four of the Corporation's 11 concessions in Argentina and approximately 96 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 to 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, 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 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.

Following major accidents in Lac-Megantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the United States National Transportation Board have recommended additional regulations for railway tank cars carrying crude oil. In June 2015, as a result of these recommendations, the Government of Canada passed the Safe and Accountable Rail Act which increased insurance obligations on the shipment of crude oil by rail, imposed a per tonne levy of $1.65 on crude oil shipped by rail to compensate victims and for environmental cleanup in the event of a railway accident. In addition to this legislation, new regulations have implemented the TC-117 standard for all rail tank cars carrying flammable liquids which formalized the commitment to retrofit, and eventually phase out DOT-111 tank cars carrying crude oil. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and add additional costs to the transportation of crude oil by rail.

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 petroleum 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. On January 29, 2016, the Government of Alberta adopted a new royalty regime which will take effect on January 1, 2017. Details of this new regime are scheduled to be finalized and released before April 21, 2016.

See "*Industry Conditions – Alberta - Royalties and Incentives*".

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.

See "*Industry Conditions – Argentina – Climate Change Regulation*" and "*Industry Conditions – Alberta - Climate Change Regulation* ".

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 be disproportionately affected by price instability. See "*Industry Conditions*".

Climate Change

Argentina is a signatory to the 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; however, these GHG emission reduction targets are not binding. 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. As a result of the UNFCCC adopting the Paris Agreement on December 12, 2015, to which Canada was a participant, the Government of Canada is expected to announce its recommendations for a framework to further reduce its GHG emission reduction targets in October 2016. 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. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition.

See "*Industry Conditions – Climate Change Regulation*".

Variations in Foreign Exchange Rates and Interest Rates

World oil and natural gas prices are quoted in USD. Crude oil and natural gas sales in Argentina are denominated in USD but collected in Argentine Pesos, natural gas sales are denominated in ARS and operating and capital costs are generally incurred in USD and ARS. Fluctuations in the United States dollar, ARS 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 an 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 in Argentina and the amount authorized thereunder is dependent on the borrowing base determined by its lender. The Corporation is required to comply with covenants under its credit facility which include certain financial ratio tests, 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 the credit facility, the lender under the credit facility could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. 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 currently does not have a credit facility in Canada.

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 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.

The Corporation currently does not hold any commodity contracts nor any other hedging arrangements.

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 is 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.

Further information is disclosed under Other Oil and Gas Information.

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 in Argentina 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

Seasonal delays can arise in the north of Argentina where heavy rain and flooding from November to February can impair access to the Corporation’s properties.

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 working interest 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 may affect a working 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 "*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 GLJ and McDaniel, the Corporation's independent engineering evaluators and KPMG LLP, the Corporation's auditors.

To the knowledge of the Corporation, GLJ 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.

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" – GLJ

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

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, 2015. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2015, 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.
3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "**COGE Handbook**") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).
4. 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.
5. The following table shows the net present value of future 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 ten percent, included in the reserves data of the Corporation evaluated for the year ended December 31, 2015, 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	**Effective Date of Evaluation Report**	**Location of Reserves (Country or Foreign Geographic Area)**	**Net Present Value of Future Net Revenue (before income taxes, 10% discount, $M USD)**			
			Audited	**Evaluated**	**Reviewed**	**Total**
GLJ Petroleum Consultants	December 31, 2015	Argentina	-	123,966	-	123,966
TOTALS			**-**	**123,966**	**-**	**123,966**

6. 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.
7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective dates of our reports.
8. 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:

GLJ Petroleum Consultants

Calgary, Alberta

Execution Date: February 29, 2016

(signed) *"Leonard L. Herchen"*
Leonard L. Herchen, P.Eng.
Vice President

SCHEDULE "B" MCDANIEL

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

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, 2015. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2015, 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.
3. 3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).
4. 4. 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.
5. The following table shows the net present value of future 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 ten percent, included in the reserves data of the Corporation evaluated for the year ended December 31, 2015, 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	**Effective Date of Evaluation Report**	**Location of Reserves (Country or Foreign Geographic Area)**	**Net Present Value of Future Net Revenue (before income taxes, 10% discount, $M USD)**			
			Audited	**Evaluated**	**Reviewed**	**Total**
McDaniel Petroleum Consultants Ltd.	December 31, 2015	Canada	-	4,399.2	-	4,399.2
TOTALS			-	**4,399.2**	-	**4,399.2**

6. 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.
7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective dates of our reports.
8. 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: February 17, 2016

(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

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.

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, contingent resources data or prospective resources data; and
- the content and filing of this report.

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

Dated at Calgary, Alberta, this 21st day of April, 2016.

(signed) *"Steven Sharpe"*
Stephen Sharpe,
Interim 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) *"Ray Smith"*
Ray Smith
Director