ZARGON
OIL & GAS LTD.

2015 ANNUAL INFORMATION FORM

March 7, 2016

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GLOSSARY OF SELECTED TERMS

Capitalized terms in this Annual Information Form have the meanings set forth below:

Entities

Board of Directors means our board of directors.

Debenture Trustee means Computershare Trust Company of Canada.

Exchangeable Shareholders means holders of Exchangeable Shares.

Newco means 1563101 Alberta Ltd.

Oakmont means Oakmont Energy Ltd.

Old Zargon means Zargon Oil & Gas Ltd., prior to completion of the Arrangement.

Shareholders mean holders of Common Shares.

TSX means Toronto Stock Exchange.

Trust means Zargon Energy Trust.

Unitholders means holders of Trust Units.

Zargon, **we**, **us** or **our** means Zargon Oil & Gas Ltd. and its controlled entities on a consolidated basis, and where the context requires, also means our predecessor issuer, the Trust and its controlled entities on a consolidated basis prior to the completion of the Arrangement.

ZEC means 1563101 Alberta Ltd.

ZEI means Zargon ExchangeCo Inc.

ZEL means Zargon Energy Ltd.

ZUSH means Zargon U.S. Holdings Ltd.

Independent Engineering

COGE Handbook means the Canadian Oil and Gas Evaluation Handbook.

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.

McDaniel means McDaniel & Associates Consultants Ltd., independent petroleum consultants of Calgary, Alberta.

McDaniel Report means the report prepared by McDaniel dated January 21, 2016 evaluating the crude oil, natural gas and natural gas liquids reserves attributable to our oil and natural gas assets at December 31, 2015.

NI 51-101 means National Instrument 51-101 – *Standards of Disclosure for Oil and Natural Gas Activities*.

Securities and Other Terms

Arrangement means the arrangement among the Trust, Old Zargon, Newco, ZEI, Oakmont, ZEL, Zargon Acquisition Corp., Zargon Oil & Gas Partnership, the holders of Trust Units and the holders of Exchangeable Shares pursuant to Section 193 of the *Business Corporations Act* (Alberta) which commenced on December 31, 2010 and was completed on January 1, 2011.

Credit Agreement means the credit agreement dated as of January 1, 2011 as amended, which is described in Note 10 to our consolidated financial statements for the year ended December 31, 2015.

Common Shares means our issued and outstanding common shares.

Convertible Debentures means the $57.5 million aggregate principal amount of our 6.00% convertible unsecured subordinated debentures due June 30, 2017, which are currently convertible at the option of the holder, at any time, into fully paid Common Shares at a conversion price of $18.80 per Common Share and which may also be redeemed by us on June 30, 2017 with cash or through the issuance of Common Shares priced at 95 percent of the current market price of the Common Shares on the maturity date.

Debenture Indenture means the indenture between us and the Debenture Trustee governing the terms of the Convertible Debentures.

Exchangeable Shares means exchangeable shares of Old Zargon.

SEC means the United States Securities and Exchange Commission.

Shareholders mean holders of Common Shares.

Trust Unit means trust units of the Trust.

ABBREVIATIONS

Oil and Natural Gas Liquids

Bbl	Barrel
bbl/d	barrels per day
Mbbl	thousand barrels
MMbbl	million barrels
NGLs	natural gas liquids

Natural Gas

gj	gigajoule
Mcf	thousand cubic feet
MMcf	million cubic feet
bcf	billion cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
MMbtu	million British Thermal Units

Other

ASP	means alkaline surfactant polymer
BOE or boe	means barrel of oil equivalent
boe/d	barrels of oil equivalent per day
Mboe	thousand barrels of oil equivalent
Mmboe	million barrels of oil equivalent
Psi	pounds per square inch
WTI	West Texas Intermediate
°API	the measure of the density or gravity of liquid petroleum products derived from a specific gravity
$000s	thousands of dollars

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	6.289
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	0.948
MMbtu	Gigajoules	1.0551

We have adopted the standard of 6 mcf: 1 bbl when converting natural gas to oil and 1 bbl: 6 mcf when converting oil to natural gas. **Boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In addition, given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.**

All dollar amounts set forth in this Annual Information Form are in Canadian dollars, except where otherwise indicated.

NOTICE TO READER

Special Note Regarding Forward-Looking Statements

Certain statements contained in this Annual Information Form, and in certain documents incorporated by reference into this Annual Information Form, constitute forward-looking statements. These statements relate to future events or our future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "budget", "plan", "continue", "estimate", "expect", "forecast", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions (including the negative thereof). In addition, there are forward-looking statements in this Annual Information Form under the headings: "*General Development of Our Business*" relating to the goals of our strategic review process; "*Description of Our Business*" relating to our business plan, focus and strategy, our capital expenditure plans and sources of funding, our hedging strategy and the benefits to be obtained therefrom, our acquisition and disposition plans and our expectations regarding the renewal of our Credit Agreement; "*Description of Our Business – Disclosure of Reserves Data and Other Oil and Natural Gas Information*" as to our reserves, future net revenues from our reserves, anticipated after-tax value of such revenues, pricing and inflation and exchange rates, future development costs and the sources of funding of our future development costs, our reclamation and abandonment obligations and the sources of funding such obligations, and the development of our proved undeveloped reserves and probable undeveloped reserves; "*Description of Our Business – Other Oil and Gas Information*" as to our future development activities and the results therefrom, drilling inventory, land expiries, hedging policies, tax horizon, production estimates, capital expenditures, and the allocation thereof, our development plans, and anticipated future production and oil recovery from our ASP project; "*Our Capital Structure*" with respect to our expectations regarding the renewal of our Credit Agreement; and "*Dividends*" with respect to our dividend policy. This information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond our control, including such as those relating to results of operations and financial condition, general economic conditions, industry conditions, changes in regulatory and taxation regimes, volatility of commodity prices, escalation of operating and capital costs, regulatory approvals required in connection with our Little Bow ASP project, currency fluctuations, the availability of services, imprecision of reserve estimates, geological, technical, drilling and processing problems, environmental risks, weather, the lack of availability of qualified personnel or management, stock market volatility, the ability to access sufficient capital from internal and external sources and competition from other industry participants for, among other things, capital, services, acquisitions of reserves, undeveloped lands and skilled personnel. Such forward-looking information is provided for the purpose of providing information about management's current expectations and plans relating to the future to allow investors to have a greater understanding of our business. Readers are cautioned that reliance on such information may not be appropriate for other purposes, such as making investment decisions.

You are cautioned that the assumptions, including among other things, future oil and natural gas prices; future capital expenditures levels; future production levels; future exchange rates; the cost of developing and expanding our assets; our ability to obtain equipment in a timely manner to carry out development activities; our ability to market our oil and natural gas successfully to current and new customers; the impact of increasing competition; our ability to obtain financing on acceptable terms; and our ability to add production and reserves through our development and acquisition activities used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Our actual results, performance, or achievement could differ materially from those expressed in, or implied by, these forward-looking statements. We can give no assurance that any of the events anticipated will transpire or occur, or if any of them do, what benefits we will derive from them. The forward-looking information contained in this document is expressly qualified by this cautionary statement. Our policy for updating forward-looking statements is that we disclaim, except as required by law, any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

We believe the expectations reflected in these forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form or as of the date specified in the documents incorporated by reference into this Annual Information Form, as the case may be.

In addition to the forward-looking statements identified above, this Annual Information Form, and the documents incorporated by reference, contains forward-looking statements pertaining to the following:

- our business plan and strategy;
- the performance characteristics of our oil and natural gas properties;
- projections of market prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development; and
- treatment under governmental regulatory regimes and tax laws.

Actual results could differ materially from those anticipated in these forward-looking statements as a result of numerous known and unknown risks and uncertainties and other factors set forth below and elsewhere in this Annual Information Form, many of which are beyond our control. Such factors include, but are not limited to:

- declines in oil and natural gas prices;
- variations in interest rates and foreign exchange rates;
- uncertainties relating to the global economy and access to capital, stock market volatility, market valuations and increased borrowing costs;
- refinancing risk for existing debt and debt service costs;
- access to external sources of capital, borrowings and equity sales;
- risks associated with our hedging activities;
- geological, technical, drilling and processing problems;

- third party credit risk;
- risks associated with the exploitation of our properties and our ability to acquire reserves;
- government regulation and control and changes in governmental legislation;
- changes in income tax laws, royalty rates and other incentive programs;
- uncertainties associated with estimating oil and natural gas reserves;
- risks associated with acquiring, developing and exploring for natural gas and other aspects of our operations;
- risks associated with the marketability of oil and natural gas;
- changes in climate change laws and other environmental regulations;
- risks associated with the exploitation of our properties and our ability to acquire reserves;
- the failure to realize anticipated benefits of acquisitions and dispositions or to manage growth;
- competition in the oil and natural gas industry;
- depletion of our reserves;
- risks associated with large projects or expansion of our activities;
- risks associated with retention of key personnel;
- risks associated with securing and maintaining our properties;
- seasonality; and
- risks associated with the timing of payment of dividends.

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 reserves described can be profitably produced in the future.

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this Annual Information Form, and the documents incorporated by reference herein, are expressly qualified by this cautionary statement. We do not undertake any obligation to publicly update or revise any forward-looking statements except as required by applicable law.

Access to Documents

Any document referred to in this Annual Information Form and described as being filed on SEDAR at www.sedar.com (including those documents referred to as being incorporated by reference in this Annual Information Form) may be obtained free of charge from us at Suite 700, 333 – 5th Avenue S.W., Calgary, Alberta, T2P 3B6.

Drilling Locations

This Annual Information Form discloses drilling locations in four categories: (i) proved undeveloped locations; (ii) probable undeveloped locations; (iii) unbooked locations; and (iv) an aggregate total of (i), (ii) and (iii). Of the 75 drilling locations referred to in this Annual Information Form, 17 are proved undeveloped locations, 16 are probable undeveloped locations, and 42 are unbooked locations. Proved undeveloped locations and probable undeveloped locations are booked and derived from the McDaniel Report and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal estimates based on our prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources (including contingent and prospective). Unbooked locations have been identified by management as an estimation of our multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that we will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which we will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the unbooked drilling locations have been derisked by drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

Oil and Gas Metrics

This Annual Information Form contains certain oil and gas metrics which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included in this document to provide readers with additional measures to evaluate our performance however, such measures are not reliable indicators of our future performance and future performance may not compare to our performance in previous periods and therefore such metrics should not be unduly relied upon.

ZARGON OIL & GAS LTD.

General

We continued as "Zargon Oil & Gas Ltd." upon the amalgamation of Old Zargon, Newco, ZAC, ZEI and Oakmont on January 1, 2011 pursuant to the Arrangement. The Arrangement involved an internal reorganization of the Trust and certain of its subsidiaries through which the trust structure was replaced with a corporate structure and the Trust was dissolved. Pursuant to the Arrangement: (i) on December 31, 2010, the Trust Units were exchanged for common shares of Newco on a one-for-one basis, the Exchangeable Shares were exchanged for common shares of Newco on the basis of 1.84716 common shares of Newco for each outstanding Exchangeable Share, and Newco acquired all of the assets and assumed all of the liabilities of the Trust; and (ii) on January 1, 2011, the Trust was dissolved and Old Zargon, Newco, ZAC, ZEI and Oakmont amalgamated. Following the Arrangement, we, together with our subsidiaries, owned, directly or indirectly, the same assets that were owned by the Trust and its subsidiaries immediately prior to the Arrangement. The Arrangement has been accounted for as a continuity of interests and, unless otherwise indicated, all information presented for the pre-Arrangement period in this Annual Information Form relates to the Trust.

On January 1, 2014, our wholly owned subsidiary, Ashton Oil & Gas Ltd., was amalgamated into us.

Our registered, head and principal office is located at Suite 700, 333 – 5th Avenue S.W., Calgary, Alberta, T2P 3B6.

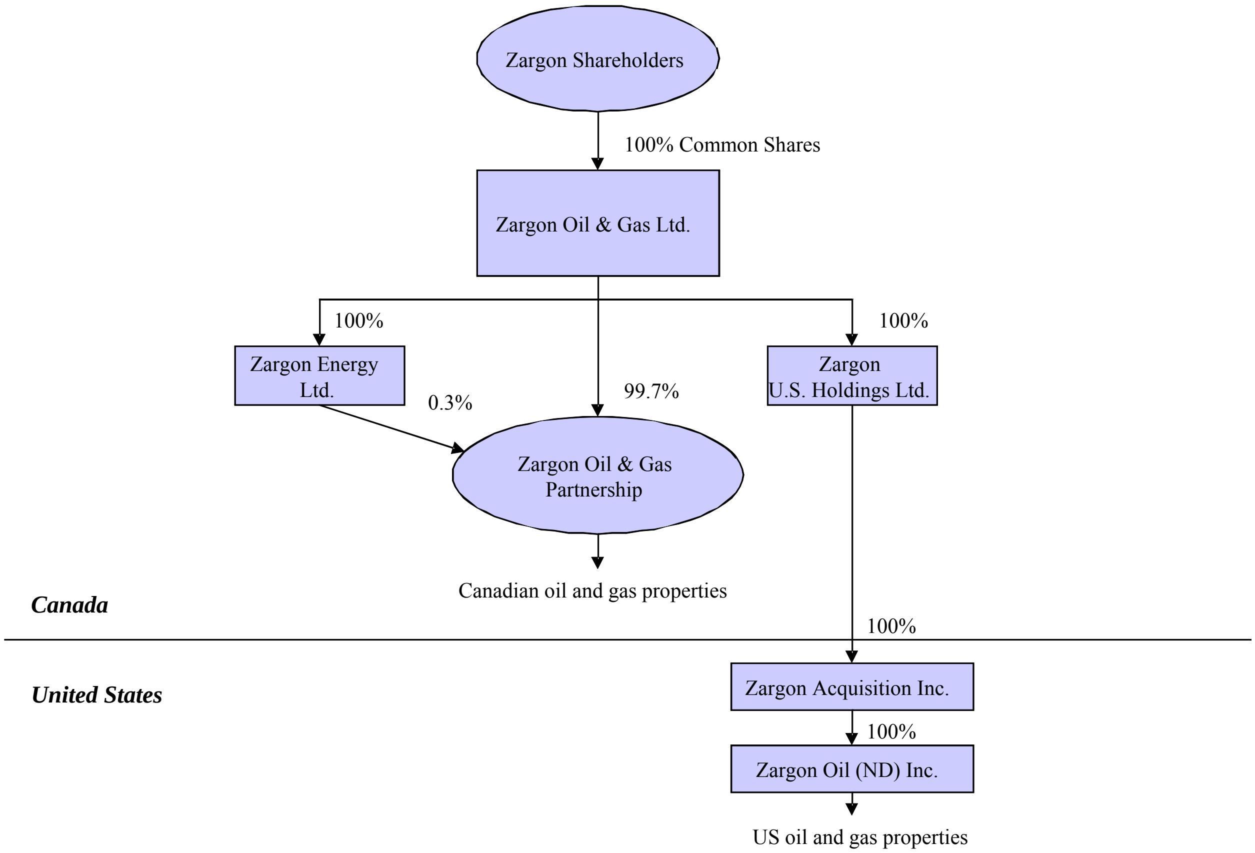
Inter-Corporate Relationships

The following are the names and percentages of voting securities that we own and the jurisdiction of incorporation, continuance or formation of our subsidiaries and partnership either, direct and indirect, as at the date hereof.

	Percentage of voting securities (directly or indirectly)	Nature of Entity	Jurisdiction of Incorporation/ Formation
Zargon Energy Ltd.	100%	Corporation	Alberta
Zargon Oil & Gas Partnership	100%	General Partnership	Alberta
Zargon U.S. Holdings Ltd.	100%	Corporation	Alberta
Zargon Acquisition Inc.	100%	Corporation	Wyoming
Zargon Oil (ND) Inc.	100%	Corporation	Delaware

Our Organization Structure

The following diagram describes the inter-corporate relationships between us and our material subsidiaries and partnership.



GENERAL DEVELOPMENT OF OUR BUSINESS

History and Development

The following provides a summary of how our business has developed over the last three years.

Developments in 2013

On February 20, 2013, we sanctioned the construction of the tertiary recovery ASP oil exploitation project at our Little Bow oil property in Southern Alberta. This ASP project entails the injection of large volumes of a dilute chemical solution into a partially depleted oil reservoir to recover incremental oil reserves. With sanctioning, phases 1 and 2 of the Little Bow ASP project will be Canada's ninth operational ASP project.

In February of 2013, we disposed of 1,100 net acres of undeveloped land and 10 boe/d in the Karr area of Alberta for $3.5 million. In the second quarter of 2013 we completed property dispositions of 130 bbl/d of oil from the Workman and Elswick, Saskatchewan properties in the Williston Basin core area for $11.6 million.

In October of 2013, we sold an additional 120 bbl/d of oil and 0.18 Mcf/d of natural gas of minor Alberta Plains North properties (Twining, Provost and Wayne) for a total consideration of $7.5 million (cash proceeds of $6.7 million).

In November of 2013, we closed an additional $12.0 million of dispositions in two separate transactions. Production from these properties totalled approximately 240 bbl/d of oil and 0.50 Mmcf/d of natural gas. The oil properties were located in the Grand Forks area of southern Alberta, and the natural gas properties were located in the Peace River Arch area of northern Alberta.

Developments in 2014

In the first half of 2014, we completed six property sale transactions, which raised $4.7 million of net proceeds from the net disposition of 32 bbl/d of oil and 1.05 Mmcf/d of natural gas. In the third quarter of 2014, we completed several property sale transactions, which raised $6.6 million of net proceeds from the net disposition of 17 bbl/d of oil and 7.08 Mmcf/d of natural gas. These transactions included the sale of our Jarrow natural gas property in East Central Alberta on September 3, 2014, that had been producing a net 5.50 Mmcf/d interest.

On December 19, 2014, we completed the sale of our Hamilton Lake property for $22.5 million in cash (before adjustments) and 1.19 million common shares of Toro Oil & Gas Ltd., which included net production to us of approximately 170 bbl/d of oil and 1.40 Mmcf/d of natural gas. The cash proceeds from these dispositions were used to reduce our indebtedness under our Credit Agreement, which was amended due to the Hamilton Lake sale to reset the borrowing base at $130 million.

In the third quarter of 2014 we set our 2015 capital budget at $46 million, which allocated $21 million to ASP related expenditures and $25 million to conventional capital expenditures. Recognizing the challenging 2015 oil price environment, in December of 2014, we completed a reassessment of our 2015 capital budget and decreased our 2015 conventional capital budget from $25 million to $12 million and set our 2015 ASP budget at $20 million. We also announced our intention to reduce our monthly dividend to $0.03 per Common Share beginning with the January 2015 dividend, payable in February 2015.

Developments in 2015

On May 14, 2015, we promoted Jeffrey Post to the position of our Chief Financial Officer. Mr. Post joined us in 2009 and has served as our Corporate Controller since February 2014.

On June 18, 2015, we amended our Credit Agreement and reduced the borrowing base to $110 million, a reduction from the previous amount of $130 million.

In June of 2015, we lowered our monthly dividend to $0.01 per Common Share beginning with the July 2015 dividend, payable in August 2015.

On July 20, 2015, Ron Wigham was appointed to our Board of Directors. Mr. Wigham is currently President of Wigham Resources Limited and a director of Spur Resources Ltd., both private oil and gas companies. He retired in 2014 as Vice-Chairman of Peters and Company, a Calgary investment dealer specializing in oil and gas and oilfield services equities.

On August 13, 2015, our Board of Directors initiated a process to identify and consider strategic and financial alternatives available to us with the ultimate goal of maximizing shareholder value.

On November 10, 2015, following the semi-annual review of our syndicated credit facilities, the borrowing base of the Credit Agreement was reduced to $88 million from $110 million.

On November 11, 2015, we announced that as a result of volatile, uncertain and exceptionally low oil prices, we had decided to suspend our monthly dividend until further notice after the November 16, 2015 dividend payment.

During 2015 our capital expenditures totaled approximately $25 million (excluding $0.6 million relating to final statement of adjustments for prior year dispositions), 76% of which was allocated to our Little Bow ASP project with $12 million allocated to ASP chemical costs and $7 million to ASP exploitation costs. The remaining $6 million of capital expenditures were allocated to minor waterflood and facility modifications that continue to enable us to have a low base oil production decline of approximately 13 percent. During the year, we drilled 6.0 net wells yielding 6.0 net oil ASP wells. We did not drill any conventional oil exploitation wells in 2015.

Significant Acquisitions

We have not completed any significant acquisitions during our most recently completed financial year for which disclosure is required under Part 8 of National Instrument 51-102 – *Continuous Disclosure Obligations*.

DESCRIPTION OF OUR BUSINESS

General

We are an Alberta based corporation engaged in the business of oil and natural gas exploration, exploitation, development, acquisition and production in Canada and the United States.

Our business plan is to deliver sustainable and profitable oil and natural gas property exploitation and production activities in the oil and natural gas industry. In recent years we have refocused our business on our long-life and low-decline conventional oil exploitation properties plus our Little Bow ASP tertiary oil project.

Capital Expenditures

Future capital expenditures on our properties will generally be of the type that are intended to maintain or improve production from our properties. We may finance capital expenditures from production revenues, the proceeds of the issue of additional Common Shares or other securities or from the proceeds of disposition of properties, borrowings, and farmouts or with working capital.

We may acquire additional properties and related tangible equipment and fund such acquisitions from production revenues, the net proceeds of any issue of additional Common Shares or other securities or from the proceeds of disposition of properties, or from borrowings, farmouts or with working capital. We may sell any of our interests in properties. In connection with the sale of any interests in our properties, we will determine whether the net proceeds of the sale should be reinvested in additional properties or capital expenditures, used to repay borrowings or distributed to our Shareholders.

Potential Acquisitions

We evaluate potential acquisitions of all types of oil and natural gas and other energy-related assets as part of our ongoing acquisition program. We are normally in the process of evaluating several potential acquisitions at any one time which individually or together could be material. We are not able to predict whether any opportunities will result in one or more acquisitions.

Competitive Conditions

The oil and natural gas industry is intensely competitive in all its phases. We compete with numerous other participants in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. Our competitors include resource companies, which may have greater financial resources, staff and facilities than ours. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery.

Cyclical and Seasonal Impact of Industry

Our operational results and financial condition will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect on our financial condition. We mitigate such price risk through closely monitoring the various commodity markets and establishing price risk management programs, as deemed necessary and through maintaining financial flexibility. See "*Risk Factors – Risks Relating to Our Business and Operations – Declines in oil and natural gas prices will adversely affect our financial condition*" and "*Risk Factors – Risks Relating to Our Business and Operations – Our hedging activities may negatively impact our income and our financial condition*".

Renegotiation or Termination of Contracts

As at the date hereof, we do not anticipate that any aspect of our business will be materially affected in the remainder of 2016 by the renegotiation or termination of contracts or subcontracts other than with respect to our Credit Agreement which has a term date of June 22, 2016 and may be extended for a further 364-day period upon our request. If the Credit Agreement is not extended, it will convert into a 365-day term loan and will be repayable in full at the end of such term. See "*Risk Factors – Risks Relating to Our Business and Operations – Our existing Credit Agreement and any replacement credit facilities may not provide sufficient liquidity*".

Bankruptcy and Similar Procedures

There have been no bankruptcy, receivership or similar proceedings against us, or any voluntary receivership, bankruptcy or similar proceeding by us within the three most recently completed financial years or proposed for us for our current financial year.

Material Restructuring Transactions

There has been no material restructuring transactions involving us within the three most recently completed financial years or currently proposed for us for our current financial year.

Human Resources

At December 31, 2015, we employed 39 full-time employees, including 26 office and 13 field employees.

Disclosure of Reserves Data and Other Oil and Natural Gas Information

This statement of reserves data and other oil and gas information set forth below is dated January 21, 2016. The effective date of the statement is December 31, 2015 and the preparation date of the statement is January 21, 2016. Readers should also refer to the Report of Management and Directors on Oil and Gas Disclosure attached hereto as Appendix A and the Report on Reserves Data by McDaniel attached hereto as Appendix B.

The reserves data set forth below is based upon an evaluation by McDaniel with an effective date of December 31, 2015 contained in the McDaniel Report. The reserves data summarizes our crude oil, natural gas liquids and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs. The McDaniel Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and CSA 51 324. We engaged McDaniel to provide an evaluation of our proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

Our reserves are in Canada in the provinces of Alberta and Saskatchewan, and in the United States in North Dakota.

We determined the future net revenue and present value of future net revenue after income taxes by utilizing McDaniel's before income tax future net revenue and our estimate of income tax. Our estimate of cash income tax makes use of the following assumptions: corporate income tax at the current legislated rate; annual general and administrative expenses at the current rate; interest expense at the current rate; tax pool deductions utilizing our existing estimated $279 million of tax pools and forecasted additions to our tax pools from capital expenditures as forecast by McDaniel and any such other additional deductions and adjustments as is and would be consistent with the manner in which we file and would file future tax returns. The after-tax net present value of our oil and gas properties reflects the tax burden of our properties on a stand-alone basis. It does not provide an estimate of the value of us as a business entity, which may be significantly different.

Future net revenue is 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. Estimated values of future net revenues presented in the tables below do not represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of our crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein. Readers should review the definitions and information contained in "*Definitions and Notes to Reserves Data Tables*" below in conjunction with the following tables and notes. For more information as to the risks involved, see "*Risk Factors – Risks Relating to Our Business and Operations*".

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2015
FORECAST PRICES AND COSTS

CANADA

	LIGHT AND MEDIUM CRUDE OIL		HEAVY CRUDE OIL		CONVETIONAL NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
Proved								
Developed Producing	4,500	3,966	2,950	2,710	6,139	5,721	97	73
Developed Non-Producing	-	-	160	142	2,005	1,715	5	3
Undeveloped	623	569	1,188	1,140	307	242	1	1
Total Proved	**5,123**	**4,535**	**4,298**	**3,992**	**8,451**	**7,678**	**103**	**77**
Probable	**2,110**	**1,848**	**4,179**	**3,767**	**5,447**	**4,699**	**51**	**36**
Total Proved Plus Probable	**7,233**	**6,383**	**8,477**	**7,759**	**13,898**	**12,377**	**154**	**113**

	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAX EXPENSES DISCOUNTED AT (%/year)				
RESERVES CATEGORY	0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)
Proved					
Developed Producing	197,801	156,344	127,509	107,230	92,486
Developed Non-Producing	6,584	4,861	3,730	2,965	2,429
Undeveloped	26,942	21,231	15,881	11,418	7,822
Total Proved	**231,327**	**182,436**	**147,120**	**121,613**	**102,737**
Probable	**212,098**	**131,669**	**85,542**	**57,656**	**39,854**
Total Proved Plus Probable	**443,425**	**314,105**	**232,662**	**179,269**	**142,591**

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAX EXPENSES DISCOUNTED AT (%/year) 0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)
Proved					
Developed Producing	197,801	156,344	127,509	107,230	92,486
Developed Non-Producing	6,584	4,861	3,730	2,965	2,429
Undeveloped	26,942	21,231	15,881	11,418	7,822
Total Proved	**231,327**	**182,436**	**147,120**	**121,613**	**102,737**
Probable	**161,362**	**103,083**	**68,429**	**46,926**	**32,874**
Total Proved Plus Probable	**392,689**	**285,519**	**215,549**	**168,539**	**135,611**

BY PRODUCT TYPE
AS OF DECEMBER 31, 2015
FORECAST PRICES AND COSTS

CANADA

RESERVES CATEGORY	PRODUCTION GROUP	NET PRESENT VALUE OF FUTURE NET REVENUE BEFORE INCOME TAX EXPENSES (discounted at 10%/year) ($000s)	UNIT VALUE (1) BEFORE INCOME TAX EXPENSES (discounted at 10%/year) ($/bbl or $/Mcf)
Proved	Light and Medium Crude Oil (2)	77,576	17.13
	Heavy Crude Oil (2)	69,112	17.33
	Conventional Natural Gas (3)	432	0.12
	Total	**147,120**	
Proved plus Probable	Light and Medium Crude Oil (2)	110,704	17.36
	Heavy Oil (2)	120,123	15.49
	Conventional Natural Gas (3)	1,835	0.34
	Total	**232,662**	

Notes:

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

SUMMARY OF OIL AND GAS RESERVES AND NET PRESENT VALUES OF FUTURE NET REVENUE AS OF DECEMBER 31, 2015 FORECAST PRICES AND COSTS

UNITED STATES

RESERVES CATEGORY	LIGHT AND MEDIUM CRUDE OIL Gross (Mbbl)	LIGHT AND MEDIUM CRUDE OIL Net (Mbbl)	HEAVY CRUDE OIL Gross (Mbbl)	HEAVY CRUDE OIL Net (Mbbl)	CONVETIONAL NATURAL GAS Gross (MMcf)	CONVETIONAL NATURAL GAS Net (MMcf)	NATURAL GAS LIQUIDS Gross (Mbbl)	NATURAL GAS LIQUIDS Net (Mbbl)
Proved								
Developed Producing	1,866	1,387	-	-	-	-	-	-
Developed Non-Producing	26	20	-	-	-	-	-	-
Undeveloped	254	194	-	-	-	-	-	-
Total Proved	**2,146**	**1,601**	-	-	-	-	-	-
Probable	**573**	**427**	-	-	-	-	-	-
Total Proved Plus Probable	**2,719**	**2,028**	-	-	-	-	-	-

NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAX EXPENSES DISCOUNTED AT (%/year)

RESERVES CATEGORY	0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)
Proved					
Developed Producing	32,196	24,767	19,024	15,208	12,611
Developed Non-Producing	727	539	408	318	255
Undeveloped	5,001	2,902	1,596	767	229
Total Proved	**37,924**	**28,208**	**21,028**	**16,293**	**13,095**
Probable	**19,837**	**9,655**	**5,608**	**3,684**	**2,644**
Total Proved Plus Probable	**57,761**	**37,863**	**26,636**	**19,977**	**15,739**

NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAX EXPENSES DISCOUNTED AT (%/year)

RESERVES CATEGORY	0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)
Proved					
Developed Producing	17,749	15,119	11,977	9,732	8,166
Developed Non-Producing	442	327	246	191	152
Undeveloped	3,043	1,575	659	77	(297)
Total Proved	**21,234**	**17,021**	**12,882**	**10,000**	**8,021**
Probable	**12,613**	**6,047**	**3,475**	**2,263**	**1,614**
Total Proved Plus Probable	**33,847**	**23,068**	**16,357**	**12,263**	**9,635**

BY PRODUCT TYPE
AS OF DECEMBER 31, 2015
FORECAST PRICES AND COSTS

UNITED STATES

RESERVES CATEGORY	PRODUCTION GROUP	NET PRESENT VALUE OF FUTURE NET REVENUE BEFORE INCOME TAX EXPENSES (discounted at 10%/year) ($000s)	UNIT VALUE (1) BEFORE INCOME TAX EXPENSES (discounted at 10%/year) ($/bbl or $/Mcf)
Proved	Light and Medium Crude Oil (2)	21,028	13.13
	Heavy Crude Oil (2)	-	
	Conventional Natural Gas (3)	-	
	Total	**21,028**	
Proved plus Probable	Light and Medium Crude Oil (2)	26,636	13.13
	Heavy Oil (2)	-	
	Conventional Natural Gas (3)	-	
	Total	**26,636**	

Notes:

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

SUMMARY OF OIL AND GAS RESERVES AND NET PRESENT VALUES OF FUTURE NET REVENUE AS OF DECEMBER 31, 2015 FORECAST PRICES AND COSTS

AGGREGATE

RESERVES CATEGORY	LIGHT AND MEDIUM CRUDE OIL Gross (Mbbl)	LIGHT AND MEDIUM CRUDE OIL Net (Mbbl)	HEAVY CRUDE OIL Gross (Mbbl)	HEAVY CRUDE OIL Net (Mbbl)	CONVETIONAL NATURAL GAS Gross (MMcf)	CONVETIONAL NATURAL GAS Net (MMcf)	NATURAL GAS LIQUIDS Gross (Mbbl)	NATURAL GAS LIQUIDS Net (Mbbl)
Proved								
Developed Producing	6,366	5,353	2,950	2,710	6,139	5,721	97	73
Developed Non-Producing	26	20	160	142	2,005	1,715	5	3
Undeveloped	877	763	1,188	1,140	307	242	1	1
Total Proved	**7,269**	**6,136**	**4,298**	**3,992**	**8,451**	**7,678**	**103**	**77**
Probable	**2,683**	**2,275**	**4,179**	**3,767**	**5,447**	**4,699**	**51**	**36**
Total Proved Plus Probable	**9,952**	**8,411**	**8,477**	**7,759**	**13,898**	**12,377**	**154**	**113**

NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAX EXPENSES DISCOUNTED AT (%/year)

RESERVES CATEGORY	0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)
Proved					
Developed Producing	229,997	181,111	146,533	122,438	105,097
Developed Non-Producing	7,311	5,400	4,138	3,283	2,684
Undeveloped	31,943	24,133	17,477	12,185	8,051
Total Proved	**269,251**	**210,644**	**168,148**	**137,906**	**115,832**
Probable	**231,935**	**141,324**	**91,150**	**61,340**	**42,498**
Total Proved Plus Probable	**501,186**	**351,968**	**259,298**	**199,246**	**158,330**

NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAX EXPENSES DISCOUNTED AT (%/year)

RESERVES CATEGORY	0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)
Proved					
Developed Producing	215,550	171,463	139,486	116,962	100,652
Developed Non-Producing	7,026	5,188	3,976	3,156	2,581
Undeveloped	29,985	22,806	16,540	11,495	7,525
Total Proved	**252,561**	**199,457**	**160,002**	**131,613**	**110,758**
Probable	**173,975**	**109,130**	**71,904**	**49,189**	**34,488**
Total Proved Plus Probable	**426,536**	**308,587**	**231,906**	**180,802**	**145,246**

BY PRODUCT TYPE
AS OF DECEMBER 31, 2015
FORECAST PRICES AND COSTS

AGGREGATE

RESERVES CATEGORY	PRODUCTION GROUP	NET PRESENT VALUE OF FUTURE NET REVENUE BEFORE INCOME TAX EXPENSES (discounted at 10%/year) ($000s)	UNIT VALUE [1] BEFORE INCOME TAX EXPENSES (discounted at 10%/year) ($/bbl or $/Mcf)
Proved	Light and Medium Crude Oil [2]	98,604	16.08
	Heavy Crude Oil [2]	69,112	17.33
	Conventional Natural Gas [3]	432	0.12
	Total	**168,148**	
Proved plus Probable	Light and Medium Crude Oil [2]	137,340	16.34
	Heavy Oil [2]	120,123	15.49
	Conventional Natural Gas [3]	1,835	0.34
	Total	**259,298**	

Notes:

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

TOTAL FUTURE NET REVENUE

(UNDISCOUNTED)
AS OF DECEMBER 31, 2015
FORECAST PRICES AND COSTS

($000s) RESERVES CATEGORY	REVENUE	ROYALTIES	OPERATING COSTS	DEVELOPMENT COSTS	ABANDONMENT AND RECLAMATION COSTS	FUTURE NET REVENUE BEFORE INCOME TAXES	INCOME TAXES	FUTURE NET REVENUE AFTER INCOME TAXES
Proved Reserves								
Canada	730,533	78,509	349,831	38,601	32,265	231,327	-	231,327
United States	178,433	45,488	80,596	5,227	9,198	37,924	16,690	21,234
Total	908,966	123,997	430,427	43,828	41,463	269,251	16,690	252,561
Proved Plus Probable Reserves								
Canada	1,285,809	142,059	555,534	106,917	37,874	443,425	50,736	392,689
United States	240,872	61,410	107,947	5,227	8,527	57,761	23,914	33,847
Total	1,526,681	203,469	663,481	112,144	46,401	501,186	74,650	426,536

Definitions and Notes to Reserves Data Tables:

1. Columns may not add due to rounding.

2. The crude oil, natural gas liquids and natural gas reserve estimates presented in the McDaniel Report are based on the definitions and guidelines contained in the COGE Handbook, NI 51-101 and CSA 51-324. A summary of certain of those definitions is set forth below.

   Reserve Categories

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

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

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

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

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

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

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

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.

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

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

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

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

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves 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.

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

Forecast Prices and Costs

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, as at December 31, 2015, inflation and exchange rates utilized in the McDaniel Report were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
AS OF DECEMBER 31, 2015
FORECAST PRICES AND COSTS

Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Bow River Hardisty API ($Cdn/bbl)	Alberta Heavy 12° API ($Cdn/bbl)	Cromer Medium 29.3° API ($Cdn/bbl)	Natural Gas AECO Price ($Cdn/ MMBTU)	Natural Gas Liquids FOB Field Gate ($Cdn/bbl) [3]	Inflation Rate[1] %/year	Exchange Rate[2] ($US/ $Cdn)
Forecast									
2016	45.00	56.60	47.00	40.50	52.60	2.70	29.20	–	0.730
2017	53.60	66.40	55.10	47.50	61.80	3.20	36.70	2.0	0.750
2018	62.40	72.80	60.40	52.10	67.70	3.55	43.90	2.0	0.800
2019	69.00	80.90	67.10	57.80	75.20	3.85	50.40	2.0	0.800
2020	73.10	83.20	69.10	59.50	77.40	3.95	52.90	2.0	0.825
2021	77.30	88.20	73.20	63.10	82.00	4.20	56.00	2.0	0.825
2022	81.60	93.30	77.40	66.70	86.80	4.45	59.20	2.0	0.825
2023	86.20	98.70	81.90	70.60	91.80	4.70	62.60	2.0	0.825
2024	87.90	100.70	83.60	72.00	93.70	4.80	63.90	2.0	0.825
2025	89.60	102.60	85.20	73.40	95.40	4.90	65.10	2.0	0.825
2026	91.40	104.70	86.90	74.90	97.40	5.00	66.50	2.0	0.825
2027	93.30	106.90	88.70	76.40	99.40	5.10	67.80	2.0	0.825
2028	95.10	108.90	90.40	77.90	101.30	5.20	69.10	2.0	0.825
2029	97.00	111.10	92.20	79.40	103.30	5.30	70.50	2.0	0.825
2030	99.00	113.40	94.10	81.10	105.50	5.40	72.00	2.0	0.825
Thereafter:	Escalate at 2.0%/year	Escalate at 2.0%/year	Escalate at 2.0%/year	Escalate at 2.0%/year	Escalate at 2.0%/year	Escalate at 2.0%/year	Escalate at 2.0%/year	2.0	0.825

Notes:

(1) Inflation rates for forecasting prices and costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.
(3) NGL mix calculated from McDaniel Report based on 45 percent propane, 35 percent butane and 20 percent natural gasoline of Edmonton propane, Edmonton butanes and Edmonton condensate and natural gasoline reference prices, respectively.

Weighted average historical prices realized by us (before the impact of financial risk management contracts) for the year ended December 31, 2015, were $2.68/Mcf for conventional natural gas, $48.34/bbl for light and medium crude oil, $22.94/bbl for natural gas liquids and $42.30/bbl for heavy crude oil.

Future Development Costs

The following tables set forth development costs deducted in the estimation of our future net revenue attributable to the reserve categories noted below.

CANADA

	Forecast Prices and Costs	
Year ($000s)	Proved Reserves	Proved Plus Probable Reserves
2016	14,960	15,050
2017	19,997	49,375
2018	3,456	19,712
2019	-	14,319
2020	-	3,946
Thereafter	188	4,515
Total Undiscounted	38,601	106,917
Total Discounted at 10%	33,541	86,280

UNITED STATES

	Forecast Prices and Costs	
Year ($000s)	Proved Reserves	Proved Plus Probable Reserves
2016	-	-
2017	5,227	5,227
2018	-	-
2019	-	-
2020	-	-
Thereafter	-	-
Total Undiscounted	5,227	5,227
Total Discounted at 10%	4,399	4,399

AGGREGATE

	Forecast Prices and Costs	
Year ($000s)	Proved Reserves	Proved Plus Probable Reserves
2016	14,960	15,050
2017	25,224	54,602
2018	3,456	19,712
2019	-	14,319
2020	-	3,946
Thereafter	188	4,515
Total Undiscounted	43,828	112,144
Total Discounted at 10%	37,940	90,679

Notes:

(1) We expect to fund the development costs of our reserves through a combination of internally generated cash flow, debt and the issuance of Common Shares or other securities.

(2) There can be no guarantee that funds will be available or that our Board of Directors will allocate funding to develop all of the reserves attributed in the McDaniel Report. Failure to develop those reserves would have a negative impact on our future cash flow.

(3) At this time, there are no expectations that the costs of funding would make development of a property uneconomic.

(4) The interest or other costs of external funding are not included in the reserves and future net revenue estimates. This would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. We do not anticipate that interest or other funding costs would make development of any property uneconomic.

(5) Estimated future abandonment and reclamation costs related to a property have been taken into account by McDaniel in determining reserves that should be attributed to a property. Reasonable estimated future well abandonment costs were

deducted in determining the aggregate future net revenue. No allowance was made, however, for reclamation of well sites not assigned reserves or the abandonment and reclamation of any facilities.

(6) The forecast price and cost assumptions assume the continuance of current laws and regulations.

(7) The extent and character of all factual data supplied to McDaniel were accepted by McDaniel as represented. No field inspection was conducted.

Reconciliation of Changes in Reserves

**RECONCILIATION OF
GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS**

CANADA

	LIGHT AND MEDIUM CRUDE OIL			HEAVY CRUDE OIL			CONVENTIONAL NATURAL GAS		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2014	5,235	2,224	7,459	4,571	4,289	8,860	9,850	5,837	15,687
Extensions & Improved Recovery	188	95	283	-	-	-	22	8	30
Technical Revisions	453	(168)	285	155	(97)	58	418	(329)	89
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	(8)	-	(8)
Economic Factors	(18)	(41)	(59)	-	(13)	(13)	-	(69)	(69)
Production	(735)	-	(735)	(428)	-	(428)	(1,831)	-	(1,831)
December 31, 2015	5,123	2,110	7,233	4,298	4,179	8,477	8,451	5,447	13,898

RECONCILIATION OF GROSS RESERVES BY PRINCIPAL PRODUCT TYPE FORECAST PRICES AND COSTS

UNITED STATES

FACTORS	LIGHT AND MEDIUM CRUDE OIL			HEAVY CRUDE OIL			CONVETIONAL NATURAL GAS		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2014	2,525	718	3,243	-	-	-	-	-	-
Extensions & Improved Recovery	-	-	-	-	-	-	-	-	-
Technical Revisions	(123)	(55)	(178)	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	(87)	(90)	(177)	-	-	-	-	-	-
Production	(169)	-	(169)	-	-	-	-	-	-
December 31, 2015	2,146	573	2,719	-	-	-	-	-	-

RECONCILIATION OF GROSS RESERVES BY PRINCIPAL PRODUCT TYPE FORECAST PRICES AND COSTS

AGGREGATE

FACTORS	LIGHT AND MEDIUM CRUDE OIL			HEAVY CRUDE OIL			CONVENTIONAL NATURAL GAS		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2014	7,760	2,942	10,702	4,571	4,289	8,860	9,850	5,837	15,687
Extensions & Improved Recovery	188	95	283	-	-	-	22	8	30
Technical Revisions	330	(223)	107	155	(97)	58	418	(329)	89
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	(8)	-	(8)
Economic Factors	(105)	(131)	(236)	-	(13)	(13)	-	(69)	(69)
Production	(904)	-	(904)	(428)	-	(428)	(1,831)	-	(1,831)
December 31, 2015	7,269	2,683	9,952	4,298	4,179	8,477	8,451	5,447	13,898

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by McDaniel in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. In our practice, proved undeveloped reserves tend to be those reserves related to wells that have been tested and not yet tied-in, wells drilled near the end of the fiscal year or wells further away from our gathering systems. In addition, such reserves may relate to planned infill drilling locations. Probable undeveloped reserves may be reserves tested or indicated by analogy to be productive, infill drilling location and lands contiguous to production. In either case, the majority of undeveloped reserves are planned to be on stream within a two-year time frame. Undeveloped proved and probable reserves represent only about 30 percent of our proved and probable reserves.

There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "*Risk Factors – Risks Relating to Our Business and Operations*".

Proved Undeveloped Reserves

The following table discloses, for each product type, the volumes of proved undeveloped reserves that were attributed in each of our most recent three financial years and, in the aggregate, before that time.

Year	**Light and Medium Oil (Mbbl)**		**Heavy Oil (Mbbl)**		**Natural Gas (MMcf)**		**NGLs (Mbbl)**	
	First Attributed	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
2013	469	524	1,525	1,525	1,035	1,035	5	5
2014	412	696	100	100	6	288	-	-
2015	118	877	-	1,188	16	307	1	1

A total of 2,065 Mbbl of oil, 307 MMcf of gas and 1 Mbbl of NGLs were assigned as proved undeveloped reserves in the McDaniel Report at December 31, 2015, representing 16 percent of our total proved reserves. In estimating future net revenue McDaniel reviewed our future development plans in order to estimate and deduct future development costs. Therefore the future development costs as set out under "*Future Development Costs*" are consistent with our future development plans if future prices meet or exceed the McDaniel price forecast. The proved undeveloped reserves are generally associated with infill/development drilling locations supported by recent drilling results and offset well data. The largest portion of the capital associated with developing proved undeveloped reserves is expected to be spent in 2016, with carryover into 2017. Within the McDaniel Report 92 percent of the capital is scheduled to be spent over the next two years.

Probable Undeveloped Reserves

The following table discloses, for each product type, the volumes of probable undeveloped reserves that were first attributed in each of our most recent three financial years and, in the aggregate, before that time.

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
	First Attributed	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
2013	700	1,033	(1,525)	3,157	(59)	2,049	(3)	22
2014	156	722	100	2,136	37	1,253	-	6
2015	94	790	-	3,110	8	1,526	-	13

A total of 3,900 Mbbl of oil, 1,526 MMcf of gas and 13 Mbbl of NGLs were assigned as gross probable undeveloped reserves in 2015, representing approximately 53 percent of our total probable reserves or 20 percent of our total proved plus probable reserves. The majority of the probable reserves assignment for us relates to properties which have proved producing reserves assigned. The bulk of the probable undeveloped reserves are assigned to projects which are actively underway or are contemplated in our forecasted capital programs based on the McDaniel price forecast. Of the total future development costs assigned in the McDaniel Report for probable undeveloped reserves 43 percent are forecast to be spent in 2016 and 2017.

Significant Factors or Uncertainties Affecting Reserves Data

Our reserves have been evaluated in accordance with NI 51-101 by McDaniel, an independent engineering firm, effective December 31, 2015. Our audit and reserves committee has reviewed the scope and methodology of McDaniel's evaluation; any significant new discoveries, additions, revisions and acquisitions, and reviewed the assumptions and consistency with prior years.

Our reserves are characterized by a high developed producing component. This reflects our core competencies of oil exploitation, increasing oil production and reserves from existing reservoirs. It is a technically complex business and each oil reservoir is treated differently depending on the interrelationships of the reservoir rock, fluids, pressures, wells and surface facilities. As circumstances change and additional data becomes available, our reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information.

Changes in future commodity prices relative to the forecasts provided under "*Pricing Assumptions*" above could have a negative impact on our reserves and in particular the development of our undeveloped reserves unless future development costs are adjusted in parallel. Other than the foregoing and the factors disclosed or described in the tables above our evaluated oil and gas properties have no material extraordinary risks or uncertainties beyond those which are inherent in an oil and gas producing company as described in our management's discussion and analysis relating to our 2015 annual audited consolidated financial statements under the heading "*Risk Factors*" and "*Outlook*", which is incorporated herein by reference. See also "*Risk Factors – Risks Relating to Our Business and Operations*" below.

Abandonment and Reclamation Costs

In connection with our operations, we will incur abandonment and reclamation costs for surface leases, wells, facilities and pipelines. We budget for and recognize as a liability the estimated present value of the future decommissioning liabilities associated with our property, plant and equipment. Our overall abandonment and reclamation costs include all costs associated with the process of restoring a property that has been disturbed by oil and gas activities to the standard imposed by the applicable government or regulatory authorities. These costs were estimated using our experience conducting abandonment and reclamation programs. We review suspended or standing wells for reactivation, recompletion or sale and conduct systematic abandonment programs for those wells that do not meet our criteria. A portion of our liability issues are retired every year and facilities are decommissioned when all the wells producing to them have been abandoned. All of our liability reduction programs take into account seasonal access, high priority and stakeholder issues, and opportunities for multi-location programs to reduce costs.

There are no unusually significant abandonment and reclamation costs associated with our properties with attributed reserves.

We will be liable for our 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.

We estimate the costs to abandon and reclaim all of our producing and shut in wells, facilities, and pipelines. Using public data and our own experience, we estimate the amount and timing of future abandonment and reclamation expenditures at an operating area level. Wells within each operating area are assigned an average cost per well to abandon and reclaim the well. The estimated expenditures are based on current regulatory standards and actual abandonment cost history.

As at December 31, 2015, we had 881.6 net wells capable of production for which we expect to incur abandonment and/or reclamation costs.

Estimated future abandonment and reclamation costs related to well abandonment and reclamation of 381.5 existing and future net wells have been taken into account by McDaniel in determining reserves that should be attributed to a property and in determining the aggregated future net revenue therefrom. No allowance was made, however, for the abandonment and reclamation of any pipelines, facilities or wells without reserves.

The additional liability associated with the 500.1 net wells not assigned reserves by McDaniel in the McDaniel Report, pipelines and facility reclamation costs, which were estimated to be $44 million (undiscounted) as at December 31, 2015, were not deducted in estimating future net revenue in the McDaniel Report.

The total amount of abandonment and reclamation costs, net of estimated salvage values, from the McDaniel Report that we expect to incur are summarized in the following table.

Period	Abandonment and Reclamation Costs Escalated at 2% Undiscounted ($000s)	Abandonment and Reclamation Costs Escalated at 2% Discounted at 10% ($000s)
Total liability as at December 31, 2015	46,401	6,302
Anticipated to be paid in 2016	-	-
Anticipated to be paid in 2017	-	-
Anticipated to be paid in 2018	-	-

We have estimated the net present value of our total asset retirement obligations to be $78 million as at December 31, 2015 based on a total future liability of $90 million. The future net revenues disclosed in this Annual Information Form based on the McDaniel Report do not contain an allowance for abandonment and reclamation costs for batteries, nor do they provide for offsetting salvage values. The McDaniel Report deducted $46.40 million (undiscounted) and $6.30 million (10 percent discount using forecast prices and costs for proved and probable reserves) for abandonment and reclamation costs in estimating the future net revenue disclosed in this Annual Information Form.

Other Oil and Gas Information

Oil and Gas Properties

The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2015. The term "net", when used to describe our share of production, means the total of our working interest share before deduction of royalties owned by others. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2015. **Estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.**

Our major properties are concentrated within Alberta and Saskatchewan in Canada and in North Dakota in the United States. Each region offers a large undeveloped land base, a vast seismic database, and significant ownership and operatorship in production facilities.

Alberta Plains

Our Alberta Plains core area holds 59 percent of our proved and probable oil and liquids reserves at year end 2015 and provided 53 percent of our 2015 oil and liquids production, primarily from the Taber South, Little Bow, Bellshill Lake and Killam Glauconite properties.

The Killam, Bellshill Lake and Taber South properties are expected to require numerous horizontal drainage wells to optimally exploit. The McDaniel Report has booked five undeveloped Killam Glauconite horizontal locations, five Bellshill Lake vertical development locations and three horizontal locations in Taber South.

The largest and most important property in this core area is Little Bow with its tertiary oil recovery opportunities plus a number of waterflood and production optimization projects. Over the last few years, we have assembled assets at Little Bow through a number of property and corporate acquisitions, which also consolidated our position in the ASP project. The Little Bow ASP tertiary oil recovery project entails the injection of chemicals as a dilute water solution into a partially depleted reservoir to recover incremental oil reserves.

In 2012, we received Alberta Energy Regulator approval and substantially completed the detailed engineering and the procurement of long-lead-time equipment for the Little Bow Upper Mannville I and P pool ASP project. During 2013, substantially all of the field construction was completed and final project commissioning commenced in the first quarter of 2014. The McDaniel Report has assigned 5.71 MMbbl of proved and probable oil and liquids reserves to the Little Bow ASP (Phase 1 and 2) project.

In March 2014, we commenced the injection of large volumes of dilute chemical solution into the partially depleted Little Bow Mannville I pool to recover incremental oil reserves. At December 31, 2015 a total of 6.5 million barrels of ASP solution has been injected into the first phase of the project. This injection volume is equal to about 20 percent of the targeted reservoir pore volume, and represents 28 percent of the total chemical bank (ASP and polymer only) scheduled to be injected in the phase 1 operation.

We completed a summer-fall 2015 optimization and remedial program which included the conversion of two additional ASP injectors, multiple producer workovers, the drilling of three producing wells, and the replacement/repair of selected ASP injection lines. This program was followed with the drilling of three additional ASP producers prior to year end. Production results from these programs have been encouraging and show improved ASP project oil rates and oil cuts.

In late April 2015, we received formal approval from the Alberta Department of Energy for royalty relief under the *Enhanced Oil Recovery Royalty Regulations* for the Little Bow ASP Project. With this approval, wells within the Little Bow phase 1 scheme area will receive a five percent Alberta Crown oil royalty rate for a period of up to 10 years. The Alberta Modernized Royalty Framework released on January 29, 2016 does not directly address the prior approvals under the existing Enhanced Oil Recovery Program. The Government of Alberta has committed to developing cost allowance programs for enhanced oil recovery schemes initiated after January 1, 2017 although the details of such programs have yet to be released. See "*Industry Conditions – Royalties and Incentives – Alberta – Alberta Enhanced Oil Recovery Program*".

We anticipate that the ASP project's current oil cut and fluid production trends will take the total phase 1 production levels to more than 600 bbl/d by the end of the 2016 second quarter (400 bbl/d of incremental ASP production plus 200 bbl/d of base waterflood production).

Although encouraged by recent Little Bow technical performance, field oil prices have continued to deteriorate and 2016 stable corporate debt levels will not be achieved without further capital reductions. Our technical analysis indicates that the Little Bow ASP project has advanced far enough that Alkaline and Surfactant ("**AS**") injections can be suspended for a few months without significantly impacting future tertiary oil recoveries. Consequently, we have elected to temporarily suspend AS injections until oil prices improve materially ($45 US/bbl WTI target), although polymer injections will be maintained to continue to move the formed oil banks to the producing wells. In the short term due to reservoir transit time, the suspension of AS injections will not have an impact on the ASP project's production trends, but after six months we anticipate ASP production growth will subside, resulting in stable production volumes until AS injections are recommenced.

Williston Basin

We have a long and profitable history in our Williston Basin core area, which encompasses a portion of southeast Saskatchewan and three counties of North Dakota. The area holds 41 percent of our proved and probable oil and liquids reserves and accounted for 47 percent of our oil and liquids production in 2015.

Based on our geophysical, geological and reservoir engineering work, we have identified 50 undeveloped Mississippian locations in the Williston Basin. Many of these locations are characterized by lower permeability reservoirs that are generally partially pressure supported by either weak aquifers or, in some cases, by mature waterfloods, and production from these locations will be characterized by relatively low initial rates, moderately high water cuts, and shallow production declines. In recent years, we have allocated most of our capital budget to the Little Bow ASP project, and virtually no drilling capital has been directed to the 50 drainage locations at the Weyburn, Elswick, Mackobee Coulee, Midale, Ralph, Steelman and Weyburn properties. The McDaniel Report has booked only 19 of these undeveloped Williston Basin horizontal drainage locations.

Oil and Gas Wells

The following table sets forth the number and status of wells in which we had a working interest as at December 31, 2015.

	Oil Wells				**Natural Gas Wells**			
	Producing		**Non-Producing**		**Producing**		**Non-Producing**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Canada								
British Columbia	-	-	-	-	-	-	3.0	1.4
Alberta	218.0	180.2	247.0	197.8	95.0	50.5	136.0	74.9
Saskatchewan	188.0	150.8	85.0	72.4	47.0	23.5	80.0	37.0
United States								
North Dakota	81.0	80.3	13.0	12.8	-	-	-	-
Total	487.0	411.3	345.0	283.0	142.0	74.0	219.0	113.3

Notes:

(1) Well counts are based on wellbores.
(2) We have no offshore wellbores.

Properties with no Attributable Reserves

The following table sets out our undeveloped land holdings as at December 31, 2015.

	Undeveloped Acres [1]	
(thousand acres)	**Gross**	**Net**
Alberta	96	53
British Columbia	5	3
Saskatchewan	20	13
United States	6	6
Total	127	75

Notes:

(1) None of our undeveloped lands have reserves attributed to them.

(2) Rights to explore, develop and exploit 16 thousand net acres of our undeveloped land holdings in Canada and 2 thousand net acres of our undeveloped land holdings in the United States are scheduled to expire by December 31, 2016.

(3) When determining gross and net acreage for two or more leases covering the same lands but different rights, the acreage is reported for each lease. Where there are multiple discontinuous rights in a single lease, the acreage is reported only once.

Significant Factors or Uncertainties Relevant to Properties with no Attributed Reserves

Our business model focuses on sustainable low decline production with little capital allocated to the acquisition, exploration or development of our properties with no attributed reserves. We do not anticipate any significant economic factors or significant uncertainties will affect any particular components of our properties with no attributed reserves. However, our decision to develop our properties with no attributed reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs and royalty regimes all of which are beyond our control. See "*Significant Factors and Uncertainties Affecting Reserves Data – Abandonment and Reclamation Costs*" and "*Risk Factors*".

Forward Contracts

We are exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates, electricity rates and interest rates in the normal course of our operations. A variety of derivative instruments are used to reduce exposure to fluctuations in commodity prices and foreign exchange rates. We are exposed to losses in the event of default by the counterparties to these derivative instruments. We manage this risk by diversifying our derivative portfolio amongst a number of financially strong counterparties. For information in relation to our marketing arrangements, see "*Marketing Arrangements*".

For details of our material commitments to sell natural gas and crude oil that were outstanding at December 31, 2015 see Note 16 to our 2015 annual audited consolidated financial statements, which is incorporated herein by reference.

Tax Horizon

We did not pay Canadian or United States income taxes in 2015.

We are a taxable entity under the *Income Tax Act* (Canada); however, based on the current forward commodity strip, we do not expect to pay cash taxes in Canada before 2017.

Costs Incurred

The following table summarizes capital expenditures related to our activities for the year ended December 31, 2015.

($ million)	Canada	United States	Total
Property Acquisition/(Disposition) Costs:			
Proved Properties [1]	0.51	-	0.51
Unproved Properties	1.96	-	1.96
Corporate Acquisitions	-	-	-
Development Costs [2]	21.57	1.13	22.70
Exploration Costs [3]	0.76	0.03	0.79
Total	24.80	1.16	25.96

Notes:

(1) Acquisitions are net of disposition of properties.
(2) Development and facilities expenditures.
(3) Cost of land acquired, geological and geophysical capital expenditures and drilling costs for 2015 exploration wells drilled.

Exploration and Development Activities

We did not participate in any exploratory wells during the year ended December 31, 2015. We participated in 6.0 (6.0 net) development wells in Canada during the year ended December 31, 2015 and did not participate in any development drilling in the United States during the year.

In 2016, we are budgeted to invest approximately $9 million in our core areas, which is comprised of a net $3 million of field capital and $6 million of ASP related expenditures. The 2016 ASP budget is comprised of $5 million of chemical costs and $1 million of general ASP exploitation expenditures. The 2016 capital budget does not include any capital for acquisitions, which may be pursued on an opportunistic basis. For more details regarding our most important current exploration and development activities for 2016 see, "*Other Oil and Gas Information – Oil and Gas Properties*" above.

Production Estimates

The following table sets out the volumes of gross production estimated in the McDaniel Report for the year ended December 31, 2016, which is reflected in the estimate of future net revenue disclosed in the tables contained under "*Disclosure of Reserves Data and Other Oil and Natural Gas Information*".

CANADA	**Light and Medium Crude Oil**	**Conventional Natural Gas**	**Natural Gas Liquids**	**Heavy Crude Oil**	**BOE**
	(bbl/d)	(Mcf/d)	(bbl/d)	(bbl/d)	(boe/d)
Total Proved	1,937	3,776	49	1,088	3,703
Total Probable	49	262	-	81	174
Total Proved Plus Probable	1,986	4,038	49	1,169	3,877

UNITED STATES	**Light and Medium Crude Oil**	**Conventional Natural Gas**	**Natural Gas Liquids**	**Heavy Crude Oil**	**BOE**
	(bbl/d)	(Mcf/d)	(bbl/d)	(bbl/d)	(boe/d)
Total Proved	404	-	-	-	404
Total Probable	9	-	-	-	9
Total Proved Plus Probable	413	-	-	-	413

Production History and Prices Received

The following tables summarize certain information in respect of our production, product prices received, royalties paid, production expenses and resulting netbacks for the periods indicated.

CANADA

	Quarter Ended			
	2015			
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**
Average Daily Production:				
Conventional Natural Gas (Mcf/d)	4,233	5,277	5,323	5,244
Light and Medium Crude Oil (bbl/d)	1,904	1,943	2,025	2,187
Heavy Crude Oil (bbl/d)	1,221	1,124	1,146	1,199
Natural Gas Liquids (bbl/d)	79	106	76	55
Combined (boe/d)	3,910	4,053	4,135	4,315
Average Price Received: (1)				
Conventional Natural Gas ($/Mcf)	2.46	2.66	2.42	3.12
Light and Medium Crude Oil ($/bbl)	44.14	48.63	59.19	45.33
Heavy Crude Oil ($/bbl)	34.76	40.80	54.53	39.75
Natural Gas Liquids ($/bbl)	26.44	12.87	36.15	19.26
Combined ($/boe)	35.56	38.44	47.89	38.06
Royalties Paid:				
Conventional Natural Gas ($/Mcf)	0.61	0.32	0.43	0.33
Light and Medium Crude Oil ($/bbl)	6.56	8.49	8.67	7.61
Heavy Crude Oil ($/bbl)	1.78	2.91	2.60	4.00
Natural Gas Liquids ($/bbl)	1.42	1.19	0.34	1.20
Combined ($/boe)	4.44	5.32	5.52	5.38
Production Costs:				
Conventional Natural Gas ($/Mcf)	2.02	2.50	2.17	2.96
Light and Medium Crude Oil ($/bbl)	27.16	27.72	24.86	25.09
Heavy Crude Oil ($/bbl)	20.57	21.59	21.69	21.62
Natural Gas Liquids ($/bbl)	15.65	6.81	14.38	10.47
Combined ($/boe)	22.15	22.71	21.26	22.44
Netback Received: (2)				
Conventional Natural Gas ($/Mcf)	(0.17)	(0.16)	(0.18)	(0.17)
Light and Medium Crude Oil ($/bbl)	10.42	12.42	25.66	12.63
Heavy Crude Oil ($/bbl)	12.41	16.30	30.24	14.13
Natural Gas Liquids ($/bbl)	9.37	4.87	21.43	7.59
Combined ($/boe)	8.97	10.41	21.11	10.24

Notes:

(1) Average price received is calculated before the impact of realized risk management gains or losses.

(2) Netbacks are calculated by subtracting royalties and operating costs from revenues before realized risk management gains or losses.

UNITED STATES

	Quarter Ended			
	2015			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production:				
Conventional Natural Gas (Mcf/d)	-	-	-	-
Light and Medium Crude Oil (bbl/d)	430	460	472	487
Heavy Crude Oil (bbl/d)	-	-	-	-
Natural Gas Liquids (bbl/d)	-	-	-	-
Combined (boe/d)	430	460	472	487
Average Price Received: (1)				
Conventional Natural Gas ($/Mcf)	-	-	-	-
Light and Medium Crude Oil ($/bbl)	40.59	44.76	53.41	37.23
Heavy Crude Oil ($/bbl)	-	-	-	-
Natural Gas Liquids ($/bbl)	-	-	-	-
Combined ($/boe)	40.59	44.76	53.41	37.23
Royalties Paid:				
Conventional Natural Gas ($/Mcf)	-	-	-	-
Light and Medium Crude Oil ($/bbl)	10.04	11.09	13.13	9.24
Heavy Crude Oil ($/bbl)	-	-	-	-
Natural Gas Liquids ($/bbl)	-	-	-	-
Combined ($/boe)	10.04	11.09	13.13	9.24
Production Costs:				
Conventional Natural Gas ($/Mcf)	-	-	-	-
Light and Medium Crude Oil ($/bbl)	19.43	15.27	15.57	18.28
Heavy Crude Oil ($/bbl)	-	-	-	-
Natural Gas Liquids ($/bbl)	-	-	-	-
Combined ($/boe)	19.43	15.27	15.57	18.28
Netback Received: (2)				
Conventional Natural Gas ($/Mcf)	-	-	-	-
Light and Medium Crude Oil ($/bbl)	11.12	18.40	24.71	9.71
Heavy Crude Oil ($/bbl)	-	-	-	-
Natural Gas Liquids ($/bbl)	-	-	-	-
Combined ($/boe)	11.12	18.40	24.71	9.71

Notes:

(1) Average price received is calculated before the impact of realized risk management gains or losses.

(2) Netbacks are calculated by subtracting royalties and operating costs from revenues before realized risk management gains or losses.

AGGREGATE

	Quarter Ended 2015			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production:				
Conventional Natural Gas (Mcf/d)	4,233	5,277	5,323	5,244
Light and Medium Crude Oil (bbl/d)	2,334	2,403	2,497	2,674
Heavy Crude Oil (bbl/d)	1,221	1,124	1,146	1,199
Natural Gas Liquids (bbl/d)	79	106	76	55
Combined (boe/d)	4,340	4,513	4,607	4,802
Average Price Received: (1)				
Conventional Natural Gas ($/Mcf)	2.46	2.66	2.42	3.12
Light and Medium Crude Oil ($/bbl)	43.49	47.89	58.10	43.86
Heavy Crude Oil ($/bbl)	34.76	40.80	54.53	39.75
Natural Gas Liquids ($/bbl)	26.44	12.87	36.15	19.26
Combined ($/boe)	36.05	39.08	48.46	37.98
Royalties Paid:				
Conventional Natural Gas ($/Mcf)	0.61	0.32	0.43	0.33
Light and Medium Crude Oil ($/bbl)	7.20	8.99	9.51	7.91
Heavy Crude Oil ($/bbl)	1.78	2.91	2.60	4.00
Natural Gas Liquids ($/bbl)	1.42	1.19	0.34	1.20
Combined ($/boe)	5.00	5.91	6.30	5.78
Production Costs:				
Conventional Natural Gas ($/Mcf)	2.02	2.50	2.17	2.96
Light and Medium Crude Oil ($/bbl)	25.73	25.34	23.11	23.85
Heavy Crude Oil ($/bbl)	20.57	21.59	21.69	21.62
Natural Gas Liquids ($/bbl)	15.65	6.81	14.38	10.47
Combined ($/boe)	21.88	21.95	20.68	22.02
Netback Received: (2)				
Conventional Natural Gas ($/Mcf)	(0.17)	(0.16)	(0.18)	(0.17)
Light and Medium Crude Oil ($/bbl)	10.56	13.56	25.48	12.10
Heavy Crude Oil ($/bbl)	12.41	16.30	30.24	14.13
Natural Gas Liquids ($/bbl)	9.37	4.87	21.43	7.59
Combined ($/boe)	9.17	11.22	21.48	10.18

Notes:

(1) Average price received is calculated before the impact of realized risk management gains or losses.

(2) Netbacks are calculated by subtracting royalties and operating costs from revenues before realized risk management gains or losses.

The following table indicates our average daily production from our core areas for the year ended December 31, 2015.

	Conventional Natural Gas (Mcf/d)	Light and Medium Crude Oil (bbl/d)	Heavy Crude Oil (bbl/d)	Natural Gas Liquids (bbl/d)	BOE (boe/d)
Alberta Plains North	2,279	758	2	23	1,163
Alberta Plains South	2,350	1	1,171	25	1,589
Williston Basin	392	1,716	-	31	1,812
Total	5,021	2,475	1,173	79	4,564

Marketing Arrangements

Natural Gas

Most of our natural gas production was sold by spot sale contracts and Alberta index prices were received. In order to control and manage credit risk and ensure competitive bids, we engage with a number of reputable counterparties for our natural gas transactions. The integration and application of these strategies resulted in an average realized price (after realized risk management gains/losses) of $2.88 per Mcf in 2015 compared to $4.04 per Mcf in 2014.

Oil and Natural Gas Liquids

We sell our oil and natural gas liquids production to a variety of customers. This allows us to benefit from specific regional advantages while maintaining pricing and delivery flexibility. In general, we market our oil production with various purchasers under one month renewable contracts and receive posted reference prices with adjustments for quality and transportation. In 2015, our average realized oil and liquids price (after realized risk management gains/losses) was $59.51 per bbl compared to $82.65 per bbl in 2014.

Risk Management Activities

Our commodity price risk management policy, which is approved by the Board of Directors, allows for the sale of up to a certain percent of our estimated before royalty production volumes for each commodity for up to a 30 month period. For details of our risk management activities in 2015 see our management's discussion and analysis relating to our 2015 annual audited consolidated financial statements under the heading "*Risk Management Activities*", which is incorporated herein by reference.

Acquisitions and Dispositions

During 2015, we completed minimal property transactions including the acquisition and disposition of oil and natural gas properties. In aggregate, we recorded $0.51 million on net property acquisitions in the year.

Social and Environmental Policy

We approach social responsibility and sustainable development by seeking a balance among economic, environmental and social issues while maintaining growth. We strive to find solutions to these issues that do not compromise the needs of future generations and place a high priority on preserving the quality of the environment, protecting the health and safety of our employees, contractors and the public in the communities in which we operate. Additionally, we actively participate in industry recognized programs that support our sustainable mindset.

We have an environmental policy in place as part of our commitment to protecting the environment while conducting our operations.

Our environmental policy states that:

- Operating in an environmentally responsible manner is key to insuring our continued growth and the industry.
- Sound environmental management is an integral component of a good business plan. Environmental stewardship reduces costs and corporate liability. It enhances shareholder value, boosts employee morale and enhances our image in the eyes of regulators and the public.
- Managing our environmental responsibilities is a team effort requiring the commitment of management, employees and contractors.
- Preventing environmental damage is cheaper than repairing damage.

- An effective environmental program helps operations staff to understand and comply with environmental laws and regulations and to minimize the costs and liabilities associated with environmental damage. It helps meet the concerns of stakeholders that environmental issues are being managed properly and will provide a due-diligence defence in the event of an environmental incident.

Our management also monitors developments related to the climate change and other environmental laws and regulations.

We are not currently impacted by proposed environmental laws and regulations relating to the control of greenhouse gases (see "*Industry Conditions – Climate Change Regulation*") as none of our facilities qualify and currently, no facility production qualifies under the criteria described in the Updated Action Plan (as defined therein). We will continue to monitor the regulatory developments and any impact that they may have on our future compliance costs.

OUR CAPITAL STRUCTURE

Share Capital

Our authorized share capital consists of an unlimited number of Common Shares without nominal or par value and 10,000,000 preferred shares without nominal or par value issuable in series (the "**Preferred Shares**"). The following is a summary of the rights, privileges, restrictions and conditions which attach to our securities. The inclusion of Preferred Shares in our authorized share capital is intended to provide us with the flexibility to raise a limited amount of future capital in the form of preferred shares. At the present time, our management is not aware of any financing structures for oil and gas companies that involve the issuance of preferred shares. The Preferred Shares will not be utilized as a defence to any take-over bid.

Common Shares

Holders of our Common Shares are entitled to notice of, to attend and to one vote per share held at any meeting of our Shareholders (other than meetings of a class or series of our shares other than the Common Shares).

Holders of our Common Shares will be entitled to receive dividends as and when declared by our Board of Directors on the Common Shares as a class, subject to prior satisfaction of all preferential rights to dividends attached to shares of other classes of our shares ranking in priority to the Common Shares in respect of dividends.

Holders of our Common Shares will be entitled in the event of our liquidation, dissolution or winding-up, whether voluntary or involuntary, or any other distribution of our assets among our Shareholders for the purpose of winding-up our affairs, and subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all shares of other classes ranking in priority to the Common Shares in respect of a return of capital on dissolution, to share rateably, together with the holders of shares of any other class of our shares ranking equally with the Common Shares in respect of a return of capital on dissolution, in such of our assets as are available for distribution.

Preferred Shares

The Preferred Shares may be issued in one or more series, at any time or from time to time. Before any shares of a particular series are issued, our Board of Directors will fix the number of shares that will form such series and will, subject to the limitations set out in the preferred share terms described below, fix the designation, rights, privileges, restrictions and conditions to be attached to the Preferred Shares of such series, including, but without in any way limiting or restricting the generality of the foregoing, the rate, amount or method of calculation of dividends thereon, the time and place of payment of dividends, the consideration for and the terms and conditions of any purchase for cancellation, retraction or redemption thereof, conversion or exchange rights (if any), and whether into or for our securities or otherwise, voting rights attached thereto (if any), the terms and conditions of any share purchase or retirement plan or sinking fund, and restrictions on the payment of dividends on any shares other than Preferred Shares or payment in respect of capital on any shares in our capital or creation or issue of debt or equity securities; the whole subject to filing of Articles of Amendment setting forth a description of such series including the designation, rights, privileges, restrictions and conditions attached to the shares of such series. Notwithstanding the foregoing: (a) our Board of Directors may at any time or from time to time change the rights, privileges, restrictions and conditions attached to unissued shares of any series of Preferred Shares; and (b) other than in the case of a failure to declare or pay dividends specified in any series of the Preferred Share, the voting rights attached to the Preferred Shares will be limited to one vote per Preferred Share at any meeting where the Preferred Shares and Common Shares vote together.

Credit Facility

We have a syndicated credit facility with a $88 million borrowing base. A $300 million demand debenture on our assets has been provided as security for these facilities. The facilities are fully revolving for a 364 day period with the provision for an annual extension at the option of the lenders and upon notice from us. The next renewal date is June 22, 2016. Should the facilities not be renewed, they convert to one year non-revolving term facilities at the end of the revolving 365 day period. Repayment would not be required until the end of the non-revolving term.

Interest rates fluctuate under the syndicated facilities with Canadian prime, US prime and US base rates plus an applicable margin between 50 basis points and 200 basis points as well as with Canadian banker's acceptance and LIBOR rates plus an applicable margin between 200 basis points and 350 basis points. Unused amounts under the facility are subject to standby fees. In the normal course of operations we enter into various letters of credit. The letters of credit reduce the amount of our available credit facilities.

Convertible Debentures

The Convertible Debentures were issued under and pursuant to the provisions of the Debenture Indenture. The following description of the Convertible Debentures is a summary of their material attributes and characteristics and is subject to the detailed provisions of the Debenture Indenture and is qualified in its entirety by reference to the Debenture Indenture which has been filed and is available on SEDAR at www.sedar.com.

General

The Convertible Debentures mature on June 30, 2017 and bear interest at an annual rate of 6.00% payable semi-annually in arrears on June 30 and December 31 in each year which commenced December 31, 2012.

Conversion Privilege

Each Convertible Debenture is convertible at the option of the holder into fully paid and non-assessable Common Shares at any time prior to 5:00 p.m. (Calgary time) on the earliest of: (i) the last business day immediately preceding their maturity and (ii) the last business day immediately preceding the date specified by us for redemption, in each case, at a conversion price of $18.80 per Common Share, representing a conversion rate of approximately 53.1915 Common Shares per $1,000 principal amount of Convertible Debentures. The conversion price may be adjusted in certain circumstances as described in the Debenture Indenture.

Interest will be paid on conversion from up to, but not including, the date of conversion. The Convertible Debentures may not be converted on June 30 or December 31 or during the five business days preceding June 30 and December 31 in each year, as the registers of the Debenture Trustee will be closed during such periods. No fractional Common Shares will be issued on any conversion of the Convertible Debenture but in lieu thereof we will satisfy fractional interests by a cash payment equal to the current market price of any fractional interest.

Redemption and Purchase

The Convertible Debentures may not be redeemed by us before June 30, 2015, except in certain limited circumstances following a change of control. On or after June 30, 2015 and prior to their maturity, the Convertible Debentures may be redeemed by us, in whole or in part from time to time, at our option on not more than 60 days' and not less than 30 days' prior written notice at a redemption price equal to the principal amount plus accrued and unpaid interest thereon, if any, provided that the current market price of the Common Shares on the date on which notice of redemption is given is not less than 125% of the conversion price. In the event that a holder of Convertible Debentures exercises their conversion right following a notice of redemption by us, the holder will be entitled to receive accrued and unpaid interest, in addition to the applicable number of Common Shares to be received on conversion, for the period from the last interest payment date up to, but not including, the date of conversion.

In the case of redemption of less than all of the Convertible Debentures, the Convertible Debentures to be redeemed will be selected by the Debenture Trustee on a pro rata basis or in such other manner as the Debenture Trustee deems equitable, subject to regulatory approvals.

We have the right to purchase Convertible Debentures for cancellation in the market, by tender or by private contract, at any time, subject to regulatory requirements.

Payment upon Redemption or at Maturity

On redemption or at maturity, as applicable, we are required to repay the indebtedness represented by the Convertible Debentures by paying to the Debenture Trustee an amount equal to the principal amount of the outstanding Convertible Debentures, together with accrued and unpaid interest thereon, if any, up to but not including the redemption date or the maturity date, as applicable. On redemption or at maturity, as applicable, we may, at our option, on not more than 60 days' and not less than 40 days' prior notice and subject to any required regulatory approvals, and provided that no event of default has occurred and is continuing, elect to satisfy our obligation to repay, in whole or in part, the principal amount of the Convertible Debentures which are to be redeemed or which have matured by issuing and delivering Common Shares to the holders of the Convertible Debentures in an amount equal to the principal amount of the Convertible Debentures divided by 95% of the current market price of the Common Shares. Any accrued and unpaid interest thereon will be paid in cash. In the event a holder of Convertible Debentures exercises its conversion rights following delivery of a notice of redemption by us, such holder shall be entitled to receive the applicable number of Common Shares to be received on conversion on the last business day immediately preceding the redemption.

No fractional Common Shares will be issued upon redemption or at maturity of the Convertible Debenture but in lieu thereof we will satisfy fractional interests by a cash payment equal to the current market price of any fractional interest.

Rank

The Convertible Debentures are subordinate to all Senior Indebtedness as more particularly described below under "*Subordination*". In the event of our insolvency, bankruptcy, liquidation, reorganization, dissolution or winding up, our assets would be made available to satisfy the obligations of the creditors of such Senior Indebtedness before being available to pay our obligations to the holders of Convertible Debentures. Accordingly, all or a substantial portion of our assets could be unavailable to satisfy the claims of the holders of Convertible Debentures.

Subordination

The payment of the principal and premium, if any, of, and interest on, the Convertible Debentures is subordinated and postponed, and subject in right of payment, to the full and final payment of all of our Senior Indebtedness. "**Senior Indebtedness**" is defined in the Debenture Indenture as all of our obligations, liabilities and indebtedness which would, in accordance with generally accepted accounting principles, be classified upon our consolidated balance sheet as our liabilities and, whether or not so classified, includes (without duplication): (a) our indebtedness for borrowed money; (b) our obligations evidenced by bonds, debentures, notes or other similar instruments; (c) our obligations arising pursuant or in relation to bankers' acceptances, letters of credit, letters of guarantee, performance bonds and surety bonds (including payment and reimbursement obligations in respect thereof) or indemnities issued in connection therewith; (d) our obligations under any swap, hedging or other similar contracts or arrangements; (e) our obligations under guarantees, indemnities, assurances, legally binding comfort letters or other contingent obligations relating to the Senior Indebtedness or other obligations of any other person which would otherwise constitute Senior Indebtedness within the meaning of this definition; (f) all of our indebtedness representing the deferred purchase price of any property including, without limitation, purchase money mortgages; (g) accounts payable to trade creditors; (h) all renewals, extensions and refinancing of any of the foregoing; (i) all declared but unpaid dividends or distributions; and (j) all costs and expenses incurred by or on behalf of any senior creditor in enforcing payment or collection of any such Senior Indebtedness, including enforcing any security interest securing the same but "Senior Indebtedness" does not include any indebtedness that would otherwise be Senior Indebtedness if it is expressly stated to be subordinate to or rank *pari passu* with the Convertible Debentures.

The Debenture Indenture provides that in the event of any insolvency or bankruptcy proceedings, or any receivership, liquidation, reorganization or other similar proceedings relative to us, or to our property or assets, or in the event of any proceedings for voluntary liquidation, dissolution or other winding-up of us, whether or not involving insolvency or bankruptcy, or any marshalling of our assets and liabilities, then holders of Senior Indebtedness will receive payment in full before the holders of Convertible Debentures will be entitled to receive any payment or distribution of any kind or character, whether in cash, property or securities, which may be payable or deliverable in any such event in respect of any of the Convertible Debentures or any unpaid interest accrued thereon. The Debenture Indenture also provides that we will not make any payment, and the holders of the Convertible Debentures will not be entitled to demand, institute proceedings for the collection of, or receive any payment or benefit (including, without any limitation, by set-off, combination of accounts or realization of security or otherwise in any manner whatsoever) on account of indebtedness represented by the Convertible Debentures: (a) in a manner inconsistent with the terms (as they exist on the date of issue) of the Convertible Debentures; or (b) at any time when a default or an event of default has occurred under the Senior Indebtedness and is continuing or upon the acceleration of Senior Indebtedness, unless the Senior Indebtedness has been repaid in full.

Repurchase upon a Change of Control

Within 30 days following the occurrence of a Change of Control, we are required to make a cash offer to purchase all of the Convertible Debentures at a price equal to 100% of the principal amount thereof plus accrued and unpaid interest thereon. A "**Change of Control**" is defined in the Debenture Indenture to include: (i) an acquisition by a person or group of persons acting jointly or in concert (within the meaning of Multilateral Instrument 62-104 – Take-Over Bids and Issuer Bids ("*MI 62-104*") and in Ontario, the *Securities Act* (Ontario) and Ontario Securities Commission Rule 62-504 – *Take-Over Bids and Issuer Bids*) of ownership of, or voting control or direction over, more than 50% of the issued and outstanding Common Shares; or (ii) the sale or other transfer of all or substantially all of our consolidated assets, excluding a sale, merger, reorganization or other similar transaction if the previous holders of the Common Shares hold at least 50% of the voting control in such merged, reorganized or other continuing entity.

If Convertible Debentures representing 90% or more of the aggregate principal amount of the Convertible Debentures outstanding on the date of the giving of notice of the Change of Control are tendered for purchase following a Change of Control (other than Convertible Debentures held at the date of the take-over bid by or on behalf of the offeror, associates or affiliates of the offeror or any one acting jointly or in concert with the offeror), we have the right to redeem all of the remaining Convertible Debentures at the same price.

Cash Change of Control

In addition to the requirement for us to make a cash offer to purchase all of the Convertible Debentures in the event of a Change of Control, if a Change of Control occurs on or before maturity in which 10% or more of the consideration for the Common Shares in the transaction or transactions constituting a Change of Control consists of: (i) cash (other than cash payments for fractional Common Shares and cash payments made in respect of dissenters' appraisal rights); (ii) equity securities (including trust units, limited partnership units or other participating securities of a trust, limited partnership or similar entity) that are not traded or intended to be traded immediately following such transactions on a recognized stock exchange; or (iii) other property that is not traded or intended to be traded immediately following such transactions on a recognized stock exchange, then subject to regulatory approvals, holders of Convertible Debentures will be entitled to convert their Debentures, subject to certain limitations, and receive, subject to and upon completion of the Change of Control, in addition to the number of Common Shares they would otherwise be entitled to receive on conversion, an additional number of Common Shares per $1,000 principal amount of Convertible Debentures. The number of such additional Common Shares per $1,000 principal amount of Debentures will be determined by reference to the provisions of the Debenture Indenture based on the date on which the Change of Control becomes effective and the price paid per Common Share in the transaction constituting the Change of Control.

Interest Payment Election

Unless an Event of Default (as defined below) under the Debenture Indenture has occurred and is continuing, we may elect, from time to time, subject to applicable regulatory approval, to satisfy our obligation to pay all or any portion of the interest on the Convertible Debentures by delivering sufficient Common Shares to the Debenture Trustee for sale, to satisfy such obligation, and holders of the Convertible Debentures will be entitled to receive a cash payment equal to the interest payable from the proceeds of the sale of such Common Shares. The Debenture Indenture sets out the procedures to be followed by us and the Debenture Trustee in order to effect this election.

Events of Default

The Debenture Indenture provides that an event of default ("**Event of Default**") in respect of the Convertible Debentures will occur if certain events described in the Debenture Indenture occur, including if any one or more of the following described events has occurred and is continuing with respect to such Convertible Debentures: (i) failure for 30 days to pay interest on the Convertible Debentures when due; (ii) failure to pay principal or premium, if any (whether by payment in cash or delivery of Common Shares), on the Convertible Debentures when due, whether at maturity, upon redemption, on a change of control, by declaration or otherwise; (iii) default in the delivery, when due, of any Common Shares or other consideration, including any Make-Whole Premium (as defined below), payable upon conversion with respect to the Convertible Debentures, which default continues for 15 days; (iv) default in the observance or performance of any other covenant or condition of the Debenture Indenture and the failure to cure (or obtain a waiver for) such default for a period of 30 days after notice in writing has been given by the Debenture Trustee or from holders of not less than 25% of the aggregate principal amount of the Convertible Debentures specifying such default and requiring us to rectify or obtain a waiver for same; (v) certain events of bankruptcy, insolvency or reorganization of us under bankruptcy or insolvency laws; and (vi) if an event of default occurs or exists under any agreement evidencing indebtedness for borrowed money (other than non-recourse debt) of us and as a result of such event of default (a) indebtedness for borrowed money thereunder in excess of $10,000,000 has become due and payable before the date it would otherwise have been due and payable, and (b) the holders of such indebtedness are entitled to commence, and have commenced, the enforcement of security they hold for such indebtedness (if any) or the exercise of any other creditors' remedies to collect such indebtedness.

If an Event of Default has occurred and is continuing, the Debenture Trustee may, in its discretion, and will, upon the request of holders of not less than 25% in principal amount of the then-outstanding Convertible Debentures declare the principal of (and premium, if any) and interest on all outstanding Convertible Debentures to be immediately due and payable. In certain cases, the holders of more than 50% of the principal amount of the Convertible Debentures then-outstanding may, on behalf of the holders of all Convertible Debentures, waive any Event of Default and/or cancel any such declaration upon such terms and conditions as such holders shall prescribe.

Offers for Convertible Debentures

The Debenture Indenture contains provisions to the effect that if an offer is made for the Convertible Debentures which is a take-over bid for the Convertible Debentures within the meaning of MI 62-104 and in Ontario, the *Securities Act* (Ontario) and Ontario Securities Commission Rule 62-504 if the Convertible Debentures were considered equity securities, and not less than 90% of the principal amount of the then-outstanding Convertible Debentures (other than Convertible Debentures held at the date of the take-over bid by or on behalf of the offeror or associates or affiliates of the offeror) are taken up and paid for by the offeror, the offeror will be entitled to acquire the Convertible Debentures held by those who did not accept the offer on the terms offered by the offeror.

Modification

The rights of the holders of Convertible Debentures may be modified in accordance with the terms of the Debenture Indenture. For that purpose, among others, the Debenture Indenture will contain certain provisions which make binding on all holders of outstanding Convertible Debentures, resolutions passed at meetings of the holders of outstanding Convertible Debentures by votes cast thereat by holders of not less than 66⅔% of the principal amount of the then-outstanding Convertible Debentures present at the meeting or represented by proxy, or rendered by instruments in writing signed by the holders of not less than 66⅔% of the principal amount of the then-outstanding Convertible Debentures. Under the Debenture Indenture, certain amendments of a technical nature or which are not prejudicial to the rights of the holders of the Convertible Debentures may be made to the Debenture Indenture without the consent of the holders of the Convertible Debentures.

DIRECTORS AND OFFICERS

Directors

The name, municipality of residence, principal occupation for the prior five years and position (including with a predecessor of us), of each of our directors is as follows:

Name and Municipality of Residence	Director Since	Principal Occupation
Craig H. Hansen Calgary, Alberta	1992	Our President & Chief Executive Officer since 1993. Mr. Hansen is also a Governor of the Canadian Association of Petroleum Producers where he is currently Chair of the Fiscal Executive Policy Group.
K. James Harrison (2) (3) Oakville, Ontario	1995	Mr. Harrison is our Chairman. He is the founder of K.J. Harrison & Partners Inc., a private client investment management firm in Toronto, Ontario. Prior to 2000, he was the Vice-Chairman and Chief Executive Officer of Connor Clark Ltd.
Kyle D. Kitagawa (1) (3) Calgary, Alberta	2001	Mr. Kitagawa brings over 25 years experience in commodity trading, equity investing, and structured finance in energy and energy intensive industries. Prior to April 2003, he held senior executive positions in a global energy trading and capital corporation. Mr. Kitagawa has been an independent businessman since 2003. In addition, Mr. Kitagawa serves as Chairman of Canadian Energy Services & Technology Corp.
Geoffrey C. Merritt (1) (3) Calgary, Alberta	2009	Mr. Merritt has been an independent businessman since April, 2009. Mr. Merritt was the founder of Masters Energy Inc., a public exploration and production company, incorporated in 2003 and acquired by us in April 2009. From 1998 to 2003, Mr. Merritt was the President and CEO of Sunfire Energy Corporation, a public oil and gas company. Prior to 1998, Mr. Merritt was the Vice President and General Manager of the oil and gas division of Pembina Corporation. Mr. Merritt currently sits on the board of Perpetual Energy Inc.
Jim Peplinski (1) (2) (3) Calgary, Alberta	1997	Mr. Peplinski is the founder of Jim Peplinski Leasing Inc., a commercial vehicle lessor. Mr. Peplinski is also the VP Business Development of the Calgary Flames Hockey Club as well as an investor in real estate and oil and gas.

Name and Municipality of Residence	Director Since	Principal Occupation
Ron Wigham (2) (3) Calgary, Alberta	2015	Mr. Wigham is an independent businessman and a director of Spur Resources Ltd. and Tourmaline Oil Corp. He retired in 2014 as Vice-Chairman of Peters and Company.
Grant A. Zawalsky (2) Calgary, Alberta	2000	Mr. Zawalsky is the Managing Partner of Burnet, Duckworth & Palmer LLP (Barristers and Solicitors) where he has been a partner since 1994. Mr. Zawalsky holds a B.Comm and LL.B. from the University of Alberta and is a member of the Law Society of Alberta. Mr. Zawalsky currently sits on the board of directors of a number of private and public companies, including NuVista Energy Ltd., PrairieSky Royalty Ltd. and Whitecap Resources Inc., and is Corporate Secretary of ARC Resources Ltd., Bonavista Energy Corporation and RMP Energy Inc. Mr. Zawalsky is also a Governor of the Calgary Petroleum Club.

Notes:

(1) Member of our audit and reserves committee.
(2) Member of our governance and compensation committee.
(3) Member of our special committee of the board.
(4) We do not have an executive committee.
(5) Directors hold office until the next annual meeting of Shareholders or until their successors are duly elected or appointed.

Officers

The name, municipality of residence, principal occupation for the prior five years and position (including with a predecessor of us), of each of our officers is as follows:

Name and Municipality of Residence	Officer Since	Office
Craig H. Hansen Calgary, Alberta	1992	President & Chief Executive Officer.
Leslie E. Burden Calgary, Alberta	2013	Vice President, Land since February, 2013; prior thereto our Manager, Land Negotiations and Manager, Land since 2010 and prior thereto Manager, Land at Masters Energy Inc. from 2005.
Randolph J. Doetzel Calgary, Alberta	2011	Vice President, Operations since June, 2011; prior thereto, our Production Manager, Williston Basin since January, 2009. Prior thereto, he held various executive, management and engineering positions at Cobalt Energy Ltd., Harvest Operations Corp., Apache Canada Ltd., and Samson Canada Ltd.

Name and Municipality of Residence	Officer Since	Office
Christopher M. Hustad Calgary, Alberta	2013	Vice President, Alberta Plains South since February, 2013; prior thereto, our Manager Exploitation, Alberta Plains South since August, 2008. Prior thereto, various management and engineering positions at Talisman Energy Inc.
Pete H.S. Janjua Calgary, Alberta	2013	Vice President, Williston Basin since February, 2013; prior thereto, our Manager Exploitation Williston Basin, Senior Technical position since 2006.
Brian G. Kergan Calgary, Alberta	2007	Vice President, Corporate Development since August, 2007.
Robert T. Moriyama Calgary, Alberta	2011	Vice President, Enhanced Recovery since January, 2011; prior thereto, he held various management and reservoir & exploitation engineering roles with Legacy Oil & Gas Ltd., CanEra Resources Inc., Pengrowth Corporation and Imperial Oil.
Jeffrey N. Post Calgary, Alberta	2015	Chief Financial Officer since May 14, 2015; prior thereto, our Corporate Controller and other positions with us since 2009.

As at March 7, 2016, our directors and officers, as a group, beneficially owned, controlled or directed, directly or indirectly, 3,912,695 Common Shares or approximately 12.8 percent of our issued and outstanding Common Shares. Our directors and officers also beneficially owned, controlled or directed, directly or indirectly $470,000 principal amount of Convertible Debentures.

Corporate Cease Trade Orders, Bankruptcies or Penalties or Sanctions

None of our directors or executive officers (nor any personal holding company of any of such persons) is, as of the date of this Annual Information Form, or was within ten years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company (including us), that was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days (collectively, an "**Order**") that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer or was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial 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.

None of our directors or executive officers (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of our securities to affect materially our control is, as of the date of this Annual Information Form, or has been, within the ten years before the date of this Annual Information Form, a director or executive officer of any company (including us) that, while that person was acting in that capacity, or 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. In addition, none of our directors or executive officers (nor any personal holding company of any such persons), or shareholder holding a sufficient number of our securities to materially affect the control of us has, within the ten years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

In addition, none of our directors or executive officers (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of our securities to affect materially the control of us, has been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority or any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

Circumstances may arise where members of our Board of Directors serve as directors or officers of corporations that are in competition to our interests. No assurances can be given that opportunities identified by such board members will be provided to us.

The *Business Corporations Act* (Alberta) 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 under the *Business Corporations Act* (Alberta). To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of the *Business Corporations Act* (Alberta).

AUDIT AND RESERVES COMMITTEE INFORMATION

Audit and Reserves Committee Mandate and Terms of Reference

The Mandate of our audit and reserves committee is attached hereto as Schedule "C". The members of our audit and reserves committee are Kyle D. Kitagawa, Geoffrey C. Merritt and Jim Peplinski.

Composition of the Audit and Reserves Committee

The members of our audit and reserves committee are independent (in accordance with National Instrument 52-110 – Audit Committees) and are financially literate.

Relevant Education and Experience

Name	Relevant Education and Experience
Kyle D. Kitagawa (Audit and Reserves Committee Chairman)	Mr. Kitagawa brings over 25 years experience in commodity trading, equity investing, and structured finance in energy and energy intensive industries. Prior to April 2003, he held senior executive positions in a global energy trading and capital corporation. Mr. Kitagawa has been an independent businessman since 2003. In addition, Mr. Kitagawa serves as Chairman of Canadian Energy Services & Technology Corp. Mr. Kitagawa holds a Master of Business Administration degree from Queen's University, a Bachelor of Commerce from the University of Calgary and is a Chartered Accountant.
Jim Peplinski	Mr. Peplinski is the founder of Jim Peplinski Leasing Inc., a commercial vehicle lessor. Mr. Peplinski is also the VP Business Development of the Calgary Flames Hockey Club as well as an investor in real estate and oil and gas.

Geoffrey C. Merritt

Mr. Merritt has over 30 years of experience in the upstream oil and gas sector. In 2003, he founded Masters Energy Inc., a public exploration and production company, which was acquired by Zargon in April 2009. From 1998 to 2003, Mr. Merritt was the President and Chief Executive Officer of Sunfire Energy. Prior to 1998, he was the Vice President and General Manager of the oil and gas division of Pembina Corporation. He currently sits on the board of Perpetual Energy Inc.

Mr. Merritt received a Bachelor of Science in Chemical Engineering from the University of Alberta in 1978 and is a graduate of the Harvard Business School.

Pre Approval Policies and Procedures

Our audit and reserves committee must pre-approve all non-audit services to be provided to us or our subsidiaries by our external auditors. Our audit and reserves committee may delegate to one or more members the authority to pre-approve non audit services, provided that the member reports to our audit and reserves committee at the next scheduled meeting and that such pre-approval and the member comply with such other procedures as may be established by our audit and reserves committee from time to time.

External Auditor Service Fees

Audit Fees

The aggregate fees billed by our external auditors, including expenses, in each of the last two fiscal years for audit services were $231,363 in 2015 and $228,575 in 2014.

Tax Fees

The aggregate fees billed in each of the last two fiscal years for professional services rendered by our external auditors, including expenses for tax compliance, tax advice and tax planning were $92,293 in 2015 and $120,052 in 2014.

All Other Fees

The aggregate fees billed in each of the last two fiscal years for products and services provided by our auditors other than services reported above were $30,663 in 2015 and $36,238 in 2014.

DIVIDENDS

We have historically made monthly dividend payments to our Shareholders on the 15th day of each month or the first business day following the 15th day. The record date for any dividend was the last business day of the month preceding the dividend date or such other date as may be determined by our Board of Directors. All of these were designated as "eligible dividends" for Canadian income tax purposes.

On November 11, 2015, as a result of volatile, uncertain and exceptionally low oil prices, we suspended our monthly dividend until further notice.

We may reinstate dividend payments in the future. Actual future cash dividends, if any, will be subject to the discretion of our Board of Directors and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by the *Business Corporations Act* (Alberta) for the declaration and payment of dividends. Our Board of Directors cannot provide assurance that cash flow will be available for distribution to Shareholders in the amounts anticipated or at all. See "*Risk Factors*".

The payment of dividends by a corporation is governed by the liquidity and insolvency tests described in the *Business Corporations Act* (Alberta). Pursuant to the *Business Corporations Act* (Alberta), after the payment of a dividend, we must be able to pay our liabilities as they become due and the realizable value of our assets must be greater than our liabilities and the legal stated capital of our outstanding securities.

Our ability to make cash dividends to Shareholders may be directly or indirectly affected in certain events as a result of certain restrictions, including restrictions set forth in our Credit Agreement and the solvency tests in the *Business Corporations Act* (Alberta). In particular, under our Credit Agreement, dividends may be only declared and paid to Shareholders if: (i) no default or event of default shall have occurred or shall occur as a result of making any such dividends; and (ii) no borrowing base shortfall shall have occurred that is continuing.

The following monthly cash dividends have been declared by us for each of the three most recently completed financial years:

For the Month Ended	Dividends per Common Share	Payment Date
January 31, 2015	$0.03	February 17, 2015
February 28, 2015	$0.03	March 16, 2015
March 31, 2015	$0.03	April 15, 2015
April 30, 2015	$0.03	May 15, 2015
May 31, 2015	$0.03	June 15, 2015
June 30, 2015	$0.03	July 15, 2015
July 31, 2015	$0.01	August 17, 2015
August 31, 2015	$0.01	September 15, 2015
September 30, 2015	$0.01	October 15, 2015
October 31, 2015	$0.01	November 16, 2015
November 30, 2015	-	-
December 31, 2015	-	-
Total	$0.22	

For the Month Ended	Dividends per Common Share	Payment Date
January 31, 2014	$0.06	February 18, 2014
February 28, 2014	$0.06	March 17, 2014
March 31, 2014	$0.06	April 15, 2014
April 30, 2014	$0.06	May 15, 2014
May 31, 2014	$0.06	June 16, 2014
June 30, 2014	$0.06	July 15, 2014
July 31, 2014	$0.06	August 15, 2014
August 31, 2014	$0.06	September 15, 2014
September 30, 2014	$0.06	October 15, 2014
October 31, 2014	$0.06	November 17, 2014
November 30, 2014	$0.06	December 15, 2014
December 31, 2014	$0.06	January 15, 2015
Total	$0.72	

For the Month Ended	Dividends per Common Share	Payment Date
January 31, 2013	$0.06	February 15, 2013
February 28, 2013	$0.06	March 15, 2013
March 31, 2013	$0.06	April 15, 2013
April 30, 2013	$0.06	May 15, 2013
May 31, 2013	$0.06	June 17, 2013
June 30, 2013	$0.06	July 15, 2013
July 31, 2013	$0.06	August 15, 2013
August 31, 2013	$0.06	September 16, 2013
September 30, 2013	$0.06	October 15, 2013
October 31, 2013	$0.06	November 15, 2013
November 30, 2013	$0.06	December 16, 2013
December 31, 2013	$0.06	January 15, 2014
Total	$0.72	

MARKET FOR SECURITIES

Common Shares

The Common Shares are listed and posted for trading on the TSX under the trading symbol "ZAR". The Common Shares commenced trading on the TSX on January 7, 2011 following completion of the Arrangement. The following table sets forth the high and low trading prices and the aggregate volume of trading of the Common Shares, as reported by the TSX for the periods indicated.

Period	High	Low	Volume
2015			
January	4.35	3.50	1,562,561
February	4.40	3.00	971,747
March	3.62	2.63	1,192,718
April	4.68	2.88	1,637,205
May	3.59	2.88	991,313
June	3.15	2.39	1,033,443
July	2.50	1.61	1,901,344
August	2.38	1.39	997,347
September	1.79	1.43	677,902
October	1.83	1.32	808,143
November	1.53	0.91	1,584,137
December	1.25	0.76	1,700,124
2016			
January	1.00	0.45	2,839,463
February	0.60	0.35	2,076,637
March (1 – 7)	0.79	0.46	581,069

Convertible Debentures

The Convertible Debentures are listed and posted for trading on the TSX under the trading symbol "ZAR.DB". The Convertible Debentures commenced trading on the TSX on May 1, 2012. The following table sets forth the high and low trading prices and the aggregate volume of trading of the Convertible Debentures, as reported by the TSX for the periods indicated.

Period	High	Low	Volume
2015			
January	89.00	59.99	18,970
February	80.00	67.48	9,690
March	77.00	65.50	10,090
April	84.35	73.51	6,640
May	83.07	75.06	8,650
June	84.01	78.00	10,740
July	80.00	67.50	13,435
August	71.00	59.98	14,570
September	63.01	59.98	6,820
October	65.25	59.50	8,000
November	66.00	43.99	18,859
December	49.69	39.99	22,340
2016			
January	42.62	21.99	17,710
February	32.00	24.50	7,850
March (1 – 7)	36.00	25.73	3,790

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 with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta and Saskatchewan, 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 our operations in a manner materially different than they will affect other oil and natural gas companies of similar size. All current legislation is a matter of public record and we are 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 Alberta and Saskatchewan.

Pricing and Marketing

Oil

In Canada, 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, the supply/demand balance and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada.. 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 National Energy Board of Canada. The National Energy Board of Canada 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) which received Royal Assent on June 29, 2012. In this transitory period, the National Energy Board of

Canada 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

Canada'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, 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 National Energy Board of Canada 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 National Energy Board of Canada and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an order from the National Energy Board of Canada. 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 National Energy Board of Canada.

The North American Free Trade Agreement

The North American Free Trade Agreement 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. The North American Free Trade Agreement 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. The North American Free Trade Agreement contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations that govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of 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, *inter alia*, 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 within 90 days of the 2015 Paris Climate Conference which concluded on December 12, 2015. 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 Modernized Royalty Framework 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 10 years until January 1, 2027. The Modernized Royalty Framework 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 Modernized Royalty Framework, including the applicable royalty rates and formulas, are scheduled to be released by March 31, 2016.

Oil sands projects are also subject to Alberta's royalty regime. The Modernized Royalty Framework does not change the oil sands royalty framework, however, the method and figures by which the royalties are calculated will be released to the public. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1% - 9% depending on the market price of oil, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil at Cushing, Oklahoma. Rates are 1% when the market price of oil is less than or equal to $55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of 1% - 9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above $55 up to 40% when oil is priced at $120 or higher.

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 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 Innovative Energy Technologies Program 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. These initiatives apply to wells drilled before January 1, 2017, for a 10 year period, until January 1, 2027. 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.

Alberta Enhanced Oil Recovery Program

The Alberta government continues to encourage the use of enhanced oil recovery methods to conserve the Province's conventional petroleum resource. Enhanced oil recovery methods use fluid injection such as chemicals (which includes ASP projects), hydrocarbons, CO_2 or nitrogen allowing additional recovery. To promote these recovery techniques, in July 2014 the Crown introduced the Enhanced Oil Recovery Program. Under the program, for which operators must apply, the oil royalty rate is set at a flat five percent for a period of up to ten years. The duration of the fixed five percent royalty rate is established by the oil reserves captured by the enhanced oil recovery project relative to what would have been captured should the project not exist. In late April 2015, we received formal approval from the Alberta Department of Energy for royalty relief under the *Enhanced Oil Recovery Royalty Regulations* for the Little Bow ASP Project. The Alberta Modernized Royalty Framework released on January 29, 2016 does not directly address the prior approvals under the existing Enhanced Oil Recovery Program. The Government of Alberta has committed to developing cost allowance programs for enhanced oil recovery schemes initiated after January 1, 2017 although the details of such programs have yet to be released.

Saskatchewan

In Saskatchewan, taxes (called Resource Surcharge) and royalties are applicable to revenue generated by corporations focused on oil and gas operations.

A Resource Surcharge on the value of sales of oil, natural gas, potash, uranium and coal in Saskatchewan is levied under authority of *The Corporation Capital Tax Act*. For resource corporations, the Resource Surcharge rate is 3%

of the value of sales of all potash, uranium and coal produced in Saskatchewan, and oil and natural gas produced from wells drilled in Saskatchewan prior to October 1, 2002. For oil and natural gas produced from wells drilled in Saskatchewan after September 30, 2002, the Resource Surcharge rate is 1.7% of the value of sales. The Resource Surcharge applies to resource trusts in addition to resource corporations.

The amount payable as a Crown royalty or a freehold production tax in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is divided into "types", being "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The vintage of oil, being "fourth tier oil", "third tier oil", "new oil" and "old oil", depends on the finished drilling date of a well and is applied to each of the three crude oil types slightly differently. Heavy oil is classified as third tier oil (produced from a vertical well having a finished drilling date on or after January 1, 1994 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1994 and before October 1, 2002), fourth tier oil (having a finished drilling date on or after October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after October 1, 2002) or new oil (conventional oil that is not classified as "third tier oil" or "fourth tier oil"). Southwest designated oil uses the same definition of fourth tier oil but third tier oil is defined as conventional oil produced from a vertical well having a finished drilling date on or after February 9, 1998 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after February 9, 1998 and before October 1, 2002 and new oil is defined as conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002. For non-heavy oil other than southwest designated oil, the same classification as heavy oil is used but new oil is defined as conventional oil produced from a vertical well completed after 1973 and having a finished drilling date prior to 1994, conventional oil produced from a horizontal well having a finished drilling date on or after April 1, 1991 and before October 1, 2002, or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1974 and before 1994 whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil. Production tax rates for freehold production are determined by first determining the Crown royalty rate and then subtracting the "Production Tax Factor" applicable to that classification of oil. Currently the production tax factor is 6.9 for "old oil", 10.0 for "new oil" and "third tier oil" and 12.5 for "fourth tier oil". The minimum rate for freehold production tax is zero.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil and apply at a reference well production rate of 100 m^3 for "old oil", "new oil" and "third tier oil", and 250 m^3 per month for "fourth tier oil". Where average wellhead prices are below the established base prices of \$100 per m^3 for third and fourth tier oil and \$50 per m^3 for new oil and old oil, base royalty rates are applied. Base royalty rates are 5% for all fourth tier oil, 10% for heavy oil that is third tier oil or new oil, 12.5% for southwest designated oil that is third tier oil or new oil, 15% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 20% for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30% for all fourth tier oil, 25% for heavy oil that is third tier oil or new oil, 35% for southwest designated oil that is third tier oil or new oil, 35% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 45% for old oil.

The amount payable as a Crown royalty or a freehold production tax in respect of natural gas production is determined by a sliding scale based on the monthly provincial average gas price published by the Government of Saskatchewan, the quantity produced in a given month, the type of natural gas, and the classification of the natural gas. Like conventional oil, natural gas may be classified as "non-associated gas" (gas produced from gas wells) or "associated gas" (gas produced from oil wells) and royalty rates are determined according to the finished drilling date of the respective well. Non-associated gas is classified as new gas (having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of at least 3,500 m^3 of gas for every m^3 of oil, and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties.

On December 9, 2010, the Government of Saskatchewan enacted the *Freehold Oil and Gas Production Tax Act, 2010* with the intention to facilitate the efficient payment of freehold production taxes by industry. Two new regulations with respect to this legislation are: (i) *The Freehold Oil and Gas Production Tax Regulations, 2012* which sets out the terms and conditions under which the taxes are calculated and paid; and (ii) *The Recovered Crude Oil Tax Regulations*, 2012 which sets out the terms and conditions under which taxes on recovered crude oil that was delivered from a crude oil recovery facility on or after March 1, 2012 are to be calculated and paid.

As with conventional oil production, base prices based on a well reference rate of 250 10^3 m^3/month are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of $1.35 per gigajoule for third and fourth tier gas and $0.95 per gigajoule for new gas and old gas, base royalty rates are applied. Base royalty rates are 5% for all fourth tier gas, 15% for third tier or new gas, and 20% for old gas. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30% for all fourth tier gas, 35% for third tier and new gas, and 45% for old gas. The current regulatory scheme provides for certain differences with respect to the administration of "fourth tier gas" which is associated gas.

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, including the following:

- *Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 8,000 m^3 for deep development vertical oil wells, 4,000 m^3 for non-deep exploratory vertical oil wells and 16,000 m^3 for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 25,000,000 m^3 for qualifying exploratory gas wells;

- *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 6,000 m^3 for non-deep horizontal oil wells and 16,000 m^3 for deep horizontal oil wells (more than 1,700 metres total vertical depth or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013* providing for a classification of the well as a qualifying exploratory gas well and resulting in a reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 25,000,000 m^3 for horizontal gas wells and after the incentive volume is produced, the gas produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002* whereby incremental production from approved waterflood projects is treated as fourth tier oil for the purposes of Crown royalty and freehold tax calculations;

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005* providing lower Crown royalty and freehold tax determinations based in part on the profitability of enhanced oil recovery projects during and subsequent to the payout of the enhanced oil recovery operations;

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing on or after April 1, 2005* providing a Crown royalty of 1% of gross revenues on enhanced oil recovery projects pre-payout and 20% of enhanced oil recovery operating income post-payout and a freehold production tax of 0% pre-payout and 8% post-payout on operating income from enhanced oil recovery projects; and

- *Royalty/Tax Regime for High Water-Cut Oil Wells* designed to extend the product lives and improve the recovery rates of high water-cut oil wells and granting "third tier oil" royalty/tax rates with a Saskatchewan Resource Credit of 2.5% for oil produced prior to April 2013 and 2.25% for oil produced on or after April 1, 2013 to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities.

On June 22, 2011, the Government of Saskatchewan released the Upstream Petroleum Industry Associated Gas Conservation Standards, which are designed to reduce emissions resulting from the flaring and venting of associated gas. The Upstream Petroleum Industry Associated Gas Conservation Standards were jointly developed with industry and the implementation of such standards commenced on July 1, 2012 for new wells and facilities licensed on or after such date. The new standards apply to existing licensed wells and facilities on July 1, 2015.

Effective April 1, 2014, the Saskatchewan Ministry of the Economy streamlined fees related to licenses and applications in the oil and gas sector by eliminating 11 different licensing fees, which resulted in an aggregate of 20,000 fee transactions per year, and replacing them with a single annual levy based on a company's production and number of wells. While the fees have been streamlined, approvals to conduct the relevant activities are still required. These changes to the fee structure are part of ongoing work by the Government of Saskatchewan to streamline the licensing, regulation and monitoring processes in the oil and gas sector.

Land Tenure

The respective provincial governments predominantly own the rights to crude oil and natural gas located in Alberta and Saskatchewan. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licenses, 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.

Each of the provinces of Alberta and Saskatchewan have 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 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, we 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 *Jobs, Growth and Long-term Prosperity Act* (Canada), 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 *Jobs, Growth and Long-term Prosperity Act* (Canada) 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 is the single regulator responsible for all energy development in Alberta. The Alberta Energy Regulator 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 Alberta Energy Regulator'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 a 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. The Integrated Resource Management System method to natural resource management sets out to engage and consult with stakeholders and the public. While the Alberta Energy Regulator 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 Alberta Energy Regulator, 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 Alberta Land Use Framework 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* provides the legislative authority for the Government of Alberta to implement the policies contained in the Alberta Land Use Framework. Regional plans established under the *Alberta Land Stewardship Act* 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 *Alberta Land Stewardship Act* 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 *Alberta Land Stewardship Act* 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 *Alberta Land Stewardship Act* 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 which came into force on September 1, 2012. The Lower Athabasca Regional Plan is the first of seven regional plans developed under the Alberta Land Use Framework. Lower Athabasca Regional Plan 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.

The Lower Athabasca Regional Plan 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 which came into force on September 1, 2014. The South Saskatchewan Regional Plan is the second regional plan developed under the Alberta Land Use Framework. The South Saskatchewan Regional Plan covers approximately 83,764 square kilometres and includes 44% of the provincial population.

The South Saskatchewan Regional Plan creates four new and four expanded conservation areas, and two new and six expanded provincial parks and recreational areas. Similar to the Lower Athabasca Regional Plan, the South Saskatchewan Regional Plan 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.

Saskatchewan

In May 2011, the Government of Saskatchewan passed changes to *The Oil and Gas Conservation Act*, the act governing the regulation of resource development operations in the province. Although the associated Bill received Royal Assent on May 18, 2011, it was not proclaimed into force until April 1, 2012, in conjunction with the release of *The Oil and Gas Conservation Regulations, 2012* and *The Petroleum Registry and Electronic Documents Regulations*. The aim of the amendments to the *The Oil and Gas Conservation Act*, and the associated regulations, is to provide resource companies investing in Saskatchewan's energy and resource industries with the best support services and business and regulatory systems available. With the enactment of the these regulations, the Government of Saskatchewan has implemented a number of operational aspects, including the increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers; and, procedural aspects including those related to Saskatchewan's participation as partner in the Petroleum Registry of Alberta.

Liability Management Rating Programs

Alberta

In Alberta, the Alberta Energy Regulator implements the Licensee Liability Rating Program. The Licensee Liability Rating Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. The *Oil and Gas Conservation Act* establishes an orphan fund to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the Licensee Liability Rating Program if a licensee or working interest participant becomes defunct. The Orphan Fund is funded by licensees in the Licensee Liability Rating Program through a levy administered by the Alberta Energy Regulator. The Licensee Liability Rating Program is designed to minimize the risk to the Orphan Fund posed by unfunded liability of licensees and prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The Licensee Liability Rating Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the Alberta Energy Regulator 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 Alberta Energy Regulator.

Made effective in three phases, from May 1, 2013 to August 1, 2015, the Alberta Energy Regulator implemented important changes to the Licensee Liability Rating Program 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 Licensee Liability Rating Program, increasing a licensee's deemed liabilities and rendering 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 Alberta Energy Regulator implemented the inactive well compliance program to address the growing inventory of inactive wells in Alberta and to increase the Alberta Energy Regulator's surveillance and compliance efforts under *Directive 013: Suspension Requirements for Wells*. The inactive well compliance program 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 inactive well compliance program 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 inactive well compliance program is available on the Alberta Energy Regulator's Digital Data Submission system.

Saskatchewan

In Saskatchewan, the Ministry of Economy implements the Licensee Liability Rating Program. The Licensee Liability Rating Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to an orphan fund established under the Licensee Liability Rating Program. The orphan fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the Licensee Liability Rating Program when a licensee or working interest participant is defunct or missing. The Licensee Liability Rating Program requires a licensee whose deemed liabilities exceed its deemed assets to post a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month for all licensees of oil, gas and service wells and upstream oil and gas facilities.

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 *United Nations Framework Convention on Climate Change* and a participant to the Copenhagen Accord (a non-binding agreement created by the *United Nations Framework Convention on Climate Change* which represents a broad political consensus and reinforces commitments to reducing greenhouse gas emissions). On January 29, 2010, Canada inscribed in the Copenhagen Accord its 2020 economy-wide target of a 17% reduction of greenhouse gas emissions from 2005 levels. This target is aligned with the United States target. In a report dated October 2013, the federal 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 greenhouse gas 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 basis, 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 greenhouse gas 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 greenhouse gas emissions regulation. In June 2012, the second US-Canada Clean Energy Dialogue Action Plan was released. The plan renewed efforts to enhance bilateral collaboration on the development of clean energy technologies to reduce greenhouse gas emissions.

On December 12, 2015, the *United Nations Framework Convention on Climate Change* 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 greenhouse gas 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 a plan within 90 days of the Paris Agreement, which will significantly increase Canada's greenhouse gas emission reduction targets.

Alberta

As part of its efforts to reduce greenhouse gas emissions, Alberta introduced legislation to address greenhouse gas emissions: the *Climate Change and Emissions Management Act* (the 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,* which imposes greenhouse gas limits, and the *Specified Gas Reporting Regulation*, which imposes greenhouse gas emissions reporting requirements. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their greenhouse gas emissions. The *Specified Gas Emitters Regulation* applies to facilities emitting more than 100,000 tonnes of greenhouse gas in 2003 or any subsequent year ("**Regulated Emitters**"), and requires reductions in greenhouse gas emissions intensity (e.g. the quantity of greenhouse gas emissions per unit of production) from emissions intensity baselines established in accordance with the *Specified Gas Emitters Regulation*.

On June 25, 2015, the Government of Alberta renewed the *Specified Gas Emitters Regulation* 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. Contributions to the Climate Change and Emissions Management Fund are made at a rate of $15 per tonne of greenhouse gas emissions, increasing to a rate of $20 per tonne of greenhouse gas emissions in 2016 and $30 per tonne of greenhouse gas emissions in 2017. Proceeds from the Climate Change and Emissions Management 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 greenhouse gas 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 greenhouse gas emissions to further reduce emissions and promote carbon competitiveness rather than rewarding past intensity levels. A 100 megatonne per year limit for greenhouse gas 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 10 megatonne limit. The existing *Specified Gas Emitters Regulation* will be replaced for large industrial facilities with a Carbon Competitiveness Regulation, 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.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced the *Management and Reduction of Greenhouse Gases Act* to regulate greenhouse gas emissions in the province. *The Management and Reduction of Greenhouse Gases Act* received Royal Assent on May 20, 2010 and will come into force on proclamation. The *Management and Reduction of Greenhouse Gases Act* establishes a framework for achieving the provincial target of a 20% reduction in greenhouse gas emissions from 2006 levels by 2020. Although the *Management and Reduction of Greenhouse Gases Act* and related regulations have yet to be proclaimed in force, draft versions indicate that the Government of Saskatchewan will permit the use of pre-certified investment credits, early action credits and emissions offsets in compliance, similar to the federal climate change initiatives. It remains unclear whether the scheme implemented by the *Management and Reduction of Greenhouse Gases Act* will be based on emissions intensity or an absolute cap on emissions.

RISK FACTORS

An investment in our Common Shares is subject to various risks including those risks inherent to the industry in which we operate. If any of these risks occur, our production, revenues and financial condition could be materially harmed, with a resulting decrease in the market price of the Common Shares. As a result, the trading price of our Common Shares could decline, and you could lose all or part of your investment.

You should carefully consider the following risk factors, as well as the other information contained in this Annual Information Form and our other public filings before making an investment decision. If any of the risks described below materialize, our business, financial condition or results of operations could be materially and adversely affected. Additional risks and uncertainties not currently known to us that we currently view as immaterial may also materially and adversely affect our business, financial condition or results of operations. Residents of the United States and other non residents of Canada should have additional regard to the risk factors under the heading "*Certain Risks for United States and Other Non-Resident Shareholders*".

The information set forth below contains "forward looking statements", which are qualified by the information contained in the section of this Annual Information Form entitled "*Notice to Reader – Special Note Regarding Forward-Looking Statements*".

Risks Relating to Our Business and Operations

Declines in oil and natural gas prices will adversely affect our financial condition

Our operational results and financial condition is dependent on the prices received for our oil and natural gas production. Since June 30, 2014, oil and natural gas prices have declined substantially. Any further declines or a sustained period at current prices of oil and natural gas would have an adverse effect on the carrying value of our proved and probable reserves, net asset value, borrowing capacity, revenues, profitability and funds from operations and ultimately on our financial condition.

Prices for crude oil and natural gas fluctuate in response to changes in the supply of, and demand for, crude oil and natural gas, market uncertainty and a variety of additional factors beyond our control. Crude oil prices are primarily determined by international supply and demand. Factors which affect crude oil prices include the actions of the Organization of the Petroleum Exporting Countries ("**OPEC**"), the condition of the Canadian, United States, European and Asian economies, government regulation, political stability in the Middle East and elsewhere, the foreign supply of crude oil, the price of foreign imports, the ability to secure adequate transportation for products, the availability of alternate fuel sources and weather conditions. Natural gas prices realized by us are affected primarily in North America by supply and demand, weather conditions, industrial demand, prices of alternate sources of energy and developments related to the market for liquefied natural gas. All of these factors are beyond our control and can result in a high degree of price volatility. Fluctuations in currency exchange rates further compound this volatility when the commodity prices, which are generally set in U.S. dollars, are stated in Canadian dollars. Recent market events and conditions, including global excess oil and natural gas supply, recent actions taken by OPEC, slowing growth in China and other emerging economies, market volatility and disruptions in Asia, and sovereign debt levels in various countries, have caused significant weakness and volatility in commodity prices. North American crude oil price differentials are also expected to continue to be volatile throughout 2016 which will have an impact on crude oil prices for Canadian producers. These events and conditions have caused a significant decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry. These difficulties have been exacerbated in Canada by the recent changes in government at a federal level and, in case of Alberta, the provincial level and the resultant uncertainty surrounding regulatory, tax and royalty changes that may be implemented by the new governments.

In addition, the inability to get the necessary approvals to build pipelines and other facilities to provide better access to markets for the oil and gas industry in western Canada has led to additional uncertainty and reduced confidence in the oil and gas industry in western Canada.

Our financial performance also depends on revenues from the sale of commodities which differ in quality and location from underlying commodity prices quoted on financial exchanges. Of particular importance are the price differentials between our light/medium oil and quoted market prices. Not only are these discounts influenced by regional supply and demand factors, they are also influenced by other factors such as transportation costs, capacity and interruptions, refining demand, the availability and cost of diluents used to blend and transport product and the quality of the oil produced, all of which are beyond our control. The supply of Canadian crude oil with demand from the refinery complex and access to those markets through various transportation outlets is currently finely balanced and, therefore, very sensitive to pipeline and refinery outages, which contributes to this volatility.

The economics of producing from some wells may change as a result of lower commodity prices, which could result in reduced production of oil or natural gas and a reduction in the volumes of our reserves. We might also elect not to produce from certain wells at lower prices. Volatile oil and natural gas prices also 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.

A prolonged period of low and/or volatile commodity prices, particularly for oil, may negatively impact our ability to meet guidance targets, maintain our business and meet all of our financial obligations as they come due, it could also result in a delay or cancellation of existing or future drilling, development or construction programs, unutilized long-term transportation commitments and a reduction in the value and amount of our reserves.

We conduct assessments of the carrying value of our assets in accordance with International Financial Reporting Standards, as issued by the International Accounting Standards Board. If crude and natural gas forecast prices decline, it could result in downward revisions to the carrying value of our assets and our net earnings could be adversely affected.

If oil and natural gas prices remain at their current levels or decrease further, our estimates of total reserves and present values thereof may be reduced.

Our reserves as at December 31, 2015 are estimated using forecast pricing escalating prices as set forth under "*Description of Our Business – Disclosure of Reserves Data and Other Oil and Natural Gas Information – Forecast Prices and Costs* ". These prices are substantially above current oil and natural gas prices. If oil and gas prices stay at current levels or drop further our reserves may be reduced as economic limits of developed reserves are reached earlier and undeveloped reserves become uneconomic at such prices. Even if some reserves remain economic at lower price levels, sustained low prices may compel us to re-evaluate our development plans and reduce or eliminate various projects with marginal economics.

In addition, lower commodity prices have restricted, and are anticipated to continue to restrict, our cash flow resulting in a reduced capital expenditure budget. As a result, we may not be able to replace our production with additional reserves and both our production and reserves could be reduced on a year over year basis.

The performance of the Little Bow ASP project will have a material impact on us

The Little Bow ASP project is one of our key assets. The performance of this asset will have a material impact on Zargon's financial performance over the coming years. Risk factors associated with our ASP project include the following, without limitation:

Production Risks

There is a risk that production and reserves relating to the existing scope of the Little Bow ASP project, and any future expansions or additions to the project will not meet forecasted oil production targets. Specific risk factors associated with the production and reserves relating to our ASP project include the following, without limitation:

- reduced oil recovery from injected chemical due to factors such as injectant performance, reservoir sweep efficiency, injectant/mineralogical interactions, thief zones, injectant degradation due to operating conditions;
- reduced injectivity and/or productivity due to pipeline or other equipment failures, loss of injection or production wells, limitations in installed equipment capacity;
- geological complexities or features in the oil reservoir unknown at the time of project implementation which affect the effectiveness of injectant in oil recovery;
- operational interruptions in Zargon's injection facility, oil processing battery, field pipelines etc. due to mechanical failure, weather related interruptions, seasonal access issues, maintenance and etc.; and
- operational interruptions due to interruptions in third party facilities and services such as pipelines, chemical suppliers, chemical transport systems and electrical power supply.

There is a risk that capital projects, undertaken to support the existing scope of the Little Bow ASP Project and future expansions or additions to the project will not be completed on time or on budget. Additionally, there is a risk that such projects may have delays, interruptions of operations or increased costs due to many factors, including, without limitation:

- inability to attract or retain sufficient numbers of qualified workers;
- construction performance falling below expected levels of output or efficiency;
- design errors;
- non-performance by, or financial failure of, third-party contractors;
- labour disputes, disruptions or declines in productivity;

- increases in materials or labour costs;
- conditions imposed by regulatory approvals;
- delays induced by weather;
- errors in construction;
- changes in project scope;
- unforeseen site surface or subsurface conditions;
- transportation or construction accidents including chemical spills or other environmental matters;
- permit requirement violation; and
- failure of existing wells, surface equipment, pipelines or other related facilities.

There is a risk that future capital costs for the chemical injectant utilized in the Little Bow ASP Project will be higher than forecast due to many factors, including without limitation:

- changes in foreign currency exchange rates;
- changes in vendor pricing;
- modifications to the project injection schedule and injection targets;
- changes in transportation charges; and
- interruptions in rail or other transport or logistical services.

Operating Costs

The operating costs of the project have the potential to vary considerably throughout the operating period and will be significant components of the cost of production of any petroleum products produced by the project. Project economics and our overall earnings may be reduced if increases in operating costs are incurred. Factors which could affect operating costs include, without limitation:

- the amount and cost of labour to operate the project;
- the cost of chemicals;
- the cost of electricity;
- power outages, particularly in winter when freeze-ups could occur;
- reliability of the facilities;
- the maintenance cost of the facilities;
- the cost of insurance; and
- catastrophic events such as fires, earthquakes, storms or explosions.

The market for heavy oil is more limited than for light and medium grades of oil, making it more susceptible to supply and demand fundamentals. Future price differentials are uncertain and any increase in heavy oil differentials could have an adverse effect on the anticipated returns from the project as well as our overall business, financial condition, results of operations and cash flows.

The amount of oil and natural gas that we can produce and sell is subject to the accessibility, availability, proximity and capacity of gathering, processing and pipeline systems

We deliver our products through gathering, processing and pipeline systems some of which we do not own. Access to the pipeline capacity for the transport of crude oil into the United States has become inadequate for the amount of Canadian production being exported to the United States and has recently resulted in significantly lower amounts being realized by Canadian producers compared with the WTI price for crude oil. Although opportunities to move oil by rail continue to grow and will provide new outlets for access to North American refineries otherwise not reachable via existing pipeline infrastructure, supply in excess of current pipeline and refining capacity is expected to continue to exist. Although we currently do not directly transport oil by rail, we could be affected by both positive and negative impacts (i.e. pricing of our oil sales from supply/demand issues) that could result from significant fluctuations to this transport method. Material structural changes are required to reduce these bottlenecks and the resulting steep price discounts.

The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect our production, operations and financial results. The federal government has signaled that it plans to review the National Energy Board approval process for large projects. This may cause the timeframe for project approvals to increase for current and future applications. There can be no assurance that such regulatory approvals will be secured on a timely basis or at all.

The lack of access to capacity in any of the gathering, processing and pipeline systems, and in particular the processing facilities, could result in our inability to realize the full economic potential of our production or in a reduction of the price offered for our production. 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 our business and, in turn, our financial condition.

A portion of our production may, from time to time, be processed through facilities owned by third parties and which we do not have control of. 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 discontinuance or decrease of operations could materially adversely affect our ability to process our production and to deliver the same for sale. Certain pipeline leaks have gained media and other stakeholder attention and may result in additional regulation or changes in law which could impede the conduct of our business or make our operations more expensive.

Following major accidents in Lac-Megantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Board have recommended additional regulations for railway tank cars carrying crude oil. These recommendations include, among others, the imposition of higher standards for all DOT-111 tank cars carrying crude oil and the increased auditing of shippers to ensure they properly classify hazardous materials and have adequate safety plans in place. 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.

Our business is impacted by a number of factors, including volatility of prices for oil and natural gas, interest rates, sources of capital, changes in legislation and those set forth below

Our ability to add to our petroleum and natural gas reserves is highly dependent on our success in exploiting existing properties and acquiring additional reserves. Our long-term commercial success depends on our ability to find, acquire, develop and commercially produce petroleum and natural gas reserves. Future oil and natural gas exploration may involve unprofitable efforts, not only from unsuccessful wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completion (including hydraulic fracturing), operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion, operating and other costs. Drilling hazards or environmental damage could greatly increase the cost of operations (including hydraulic fracturing), and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees. New wells we drill or participate in may not become productive and we may not recover all or any portion of our investment in wells we drill or participate in. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project.

Operating costs for our underlying properties will directly impact the amount of cash flow received by us. Labour costs, electricity, gas processing, well servicing and chemicals are a few of our operating costs that are susceptible to material fluctuation. There is no assurance that further commercial quantities of petroleum and natural gas will be discovered or acquired by us.

The level of production from our existing properties may decline at rates greater than anticipated due to unforeseen circumstances, many of which are beyond our control. A significant decline in production could result in materially lower revenues and cash flow.

There is no assurance we will be successful in developing additional reserves or acquiring additional reserves on terms that meet our investment objectives. Without these reserves additions, our reserves will deplete and consequently, either production from, or the average reserves life of, our properties will decline, which will result in a reduction in the value of our Common Shares.

Variations in interest rates and foreign exchange rates could affect our financial condition

There is a risk that interest rates will increase given the current historical low level of interest rates. An increase in interest rates could result in a significant increase in the amount we pay to service debt and affect our ability to fund ongoing operations and could impact the market price of the Common Shares.

World oil and natural gas prices are quoted in United States dollars. The Canadian/U.S. dollar exchange rate, which fluctuates over time, consequently affects the price received by Canadian producers of oil and natural gas. Material increases in the value of the Canadian dollar related to the U.S. dollar will negatively affect our production revenue. Accordingly, Canadian/United States exchange rates could affect the future value of our as determined by our independent evaluator.

A decline in the value of the Canadian dollar relative to the United States dollar provides a competitive advantage to United States companies in acquiring Canadian oil and gas properties and may make it more difficult for us to replace reserves through acquisitions.

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

Continued uncertainty in the industry may restrict the availability or increase the cost of borrowing required for future development and acquisitions

Due to the conditions in the oil and gas industry and/or global economic volatility, we may from time to time have restricted access to capital and increased borrowing costs. The current conditions in the oil and gas industry have negatively impacted the ability of oil and gas companies to access additional financing. Continued depressed oil and natural gas prices have caused decreases, and may cause further decreases, in our cash flow. To the extent that external sources of capital become limited, unavailable or available on onerous terms, our ability to access sufficient capital for our capital expenditures and acquisitions could be impaired and, as a result, may have a material adverse effect on our ability to execute our business strategy and on our financial condition. There can be no assurance that financing will be available or sufficient to meet these requirements or for other corporate purposes or, if financing is available, that it will be on terms appropriate and acceptable to us. Should the lack of financing and uncertainty in the capital markets adversely impact our ability to refinance debt, additional equity may be issued resulting in a dilutive effect on current and future Shareholders.

We have been historically reliant on external sources of capital, borrowings and equity sales and, if unavailable, our financial condition will be adversely affected

Amounts paid in respect of interest and principal on debt may reduce future capital expenditures. Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to be applied to debt service. Although we believe the Credit Agreement will be sufficient for our immediate requirements, there can be no assurance that the amount will be adequate for our future financial obligations including our future capital expenditure program, or that we will be able to obtain additional funds.

As future capital expenditures will be financed out of funds flow from operating activities, borrowings and possible future security issuances, our ability to do so is dependent on, among other factors, the overall state of capital markets and investor appetite for investments in the energy industry and our securities in particular.

From time to time we may enter into transactions which may be financed in whole or in part with debt. The level of our indebtedness from time to time could impair our ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise. To the extent that external sources of capital become limited or unavailable or available on onerous terms, our ability to make capital investments and maintain or expand existing assets and reserves may be impaired, and our assets, liabilities, business, financial condition and results of operations. The current conditions in the oil and gas industry have negatively impacted the ability of oil and gas companies to access additional financing.

Shareholders may suffer dilution in connection with future issuances of Common Shares. In the normal course of making capital investments to maintain and expand our oil and gas reserves additional Common Shares may be issued. Additionally, from time to time we may issue Common Shares in order to finance significant acquisitions or development projects or to reduce debt and maintain a more optimal capital structure. Our success is, in part, dependent on our ability to raise capital from time to time by issuing additional Common Shares. Shareholders may suffer dilution as a result of these offerings if, for example, the cash flow, production or reserves from the acquired assets do not reflect the additional number of Common Shares issued to acquire those assets. Shareholders may also suffer dilution in connection with future issuances of Common Shares to complete acquisitions.

We believe that estimated funds from operations, together with our Credit Agreement, will be sufficient to substantially finance our current operations and planned capital expenditures for the ensuing year. The timing of most of our capital expenditures is discretionary and there are no material long-term capital expenditure commitments. However, if funds from operations are lower than expected or capital costs for these projects exceed current estimates, or if we incur major unanticipated expenses related to development or maintenance of our existing properties, we may be required to seek additional capital to maintain our capital expenditures at planned levels. Failure to obtain any financing necessary for our capital expenditure plans may result in a delay in development or production on our properties.

Our hedging activities may negatively impact our income and our financial condition

We may manage the risk associated with changes in commodity prices by entering into petroleum or natural gas price hedges. If we hedge our commodity price exposure, we may forego some of the benefits we would otherwise experience if commodity prices were to increase. As at December 31, 2015, our income statement reflected $9.7 million of unrealized losses resulting from hedges to protect our commodity risk exposure. For more information in relation to our commodity hedging program, see "*Description of our Business – Disclosure of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Gas Information – Forward Contracts*". We may initiate certain hedges to attempt to mitigate the risk of the Canadian dollar appreciating against the U.S. dollar. An increase in the Canada/U.S. foreign exchange rate will impact future dividends and the future value of our reserves as determined by independent evaluators. These hedging activities could expose us to losses and to credit risk associated with counterparties with which we contract.

In addition, our current hedging contracts provide a benefit to us during this period of low oil and natural gas prices. This benefit will only be realized for the period and for the commodity quantities in those contracts. Assuming that the futures market for oil and natural gas remains at current pricing levels, a substantial amount of the benefits from such derivatives contracts will be realized by the end of June, 2016 and additional hedges at prices would not be available at or near such prior prices, which will adversely impact our revenues.

Failure of third parties to meet their contractual obligations to us may have a material adverse affect on our financial condition

We are exposed to third party credit risk through our contractual arrangements with our current or future joint venture partners, third party operators, marketers of our petroleum and natural gas production, hedge counterparties and other parties. We manage this credit risk by entering into sales contracts with creditworthy entities and reviewing our exposure to individual entities on a regular basis. However, in the event such parties fail to meet their contractual obligations to us, such failures may have a material adverse effect on our business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in our ongoing capital program, potentially delaying the program and the results of such program until we find a suitable alternative partner.

Our business is heavily regulated and such regulation increases our costs and may adversely affect our financial condition

The oil and natural gas industry in Canada is subject to federal, provincial and municipal legislation and regulation governing such matters as land tenure, prices, royalties, production rates, environmental protection controls, the exportation of crude oil, natural gas and other products, as well as other matters. The industry is also subject to regulation by governments in such matters as the awarding or acquisition of exploration and production rights, oil sands or other interests, the imposition of specific drilling obligations, environmental protection controls, control over the development and abandonment of fields and sites (including restrictions on production) and possibly the expropriation or cancellation of contract rights. Governments may regulate or intervene with respect to prices, taxes, royalties and the exportation of oil and natural gas and such regulations may be amended from time to time. Regulation increases our costs which will result in a reduction in funds from operations.

In order to conduct oil and gas operations, we require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities. There can be no assurance that we will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that we may wish to undertake. See "*Industry Conditions*".

Alberta and Saskatchewan have developed liability management programs 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. These programs generally involve 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 our 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. In addition, the liability management system may prevent or interfere with our ability to acquire or dispose of assets as both the vendor and the purchaser of oil and gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. See "*Industry Conditions - Liability Management Rating Programs*".

In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, our 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).

There are numerous uncertainties inherent in estimating quantities of recoverable petroleum and natural gas reserves, including many factors beyond our control

Although we, together with McDaniel, have carefully prepared the reserves figures included in this Annual Information Form and believe that the methods of estimating reserves have been verified by operating experience, such figures are estimates and no assurance can be given that the indicated levels of reserves will be produced.

In general, estimates of economically recoverable petroleum and natural gas reserves and the future net revenues therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of petroleum and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. All such estimates are based on professional judgment and classifications of reserves, which, by their nature have a high degree of subjectivity. For those reasons, estimates of the economically recoverable petroleum 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 reserves and recovery information contained in the McDaniel Report is only an estimate and the actual production and ultimate reserves from the properties may be greater or less than the estimates prepared by McDaniel and such variations could be material. The McDaniel Report has been prepared using certain commodity price assumptions which are described in the notes to the reserves tables. If we realize lower prices for crude oil, NGLs and natural gas and they are substituted for the price assumptions utilized in the McDaniel Report, the present value of estimated future net revenues for our reserves and our net asset value would be reduced and the reduction could be significant. The estimates in the McDaniel Report are based, in part, on the timing and success of activities we intend to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the McDaniel Report will be reduced, in future years, to the extent that such activities do not achieve the level of success assumed in the McDaniel Report.

Estimates of proved and probable oil and gas reserves include undeveloped reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is still required before such wells begin production. Reserves may be recognized when plans are in place to make the required investments to convert these undeveloped reserves to producing. Circumstances such as a sustained decline in commodity prices or poorer than expected results from initial activities could cause a change in the investment or development plans which could result in a material change in our reserves estimates.

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

Acquiring, developing and exploring for oil and natural gas involves many risks, which even a combination of experience, knowledge and careful evaluation may not be able to overcome

These risks include, but are not limited to, encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, craterings, equipment failures and other accidents, sour gas releases, oil and natural gas spills, uncontrollable flows of oil, natural gas or well fluids, the invasion of water into producing formations, adverse weather conditions, pollution, other environmental hazards, fires, transport accidents and spills and delays in payments between parties caused by operation or economic matters which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment, personal injuries, loss of life and other hazards, all of which could result in liability. These risks will increase as we undertake more exploratory activity. Drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, the shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. Although we maintain insurance in accordance with customary industry practice, we are not fully insured against all of these risks nor are all such risks insurable and in certain circumstances we may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. In addition, the nature of these risks is such that liabilities could exceed policy limits, in which event we could incur significant costs that could have a material adverse effect upon our financial condition.

Exploration and development risks arise due to the uncertain results of searching for and producing petroleum and natural gas using imperfect scientific methods. These risks are mitigated by using highly skilled staff, focusing exploration efforts in areas in which we have existing knowledge and expertise or access to such expertise, using up to date technology to enhance methods and controlling costs to maximize returns.

Losses resulting from the occurrence of any of these risks may have a material adverse effect on our business, financial condition, results of operations and prospects.

The operation of a portion of our properties is largely dependent on the ability of third party operators, and harm to their business could cause delays and additional expenses in our receiving revenues

The continuing production from a property, and to some extent the marketing of production, is dependent upon the ability of the operators of our properties. Approximately 10.3 percent of our properties are operated by third parties, based on daily production. Our return on assets operated by others depends upon a number of factors that may be outside of our control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices. In addition, due to the current low and volatile commodity prices, many companies, including companies that may operate some of the assets in which we have an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which we have an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations we may be required to satisfy such obligations and to seek recourse from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, us potentially becoming subject to additional liabilities relating to such assets and us having difficulty collecting revenue due from such operators. Any of these factors could materially adversely affect our financial and operational results.

In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of the properties, and by the operator to our operating entities, payments between any of such parties may also be delayed by restrictions imposed by lenders, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, blowouts or other accidents, recovery by the operator of expenses incurred in the operation of properties or the establishment by the operator of reserves for such expenses. Our return on assets operated by others therefore will depend upon a number of factors that may be outside of our control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices. Losses resulting from the occurrence of any of these risks may have a material adverse effect on our business, financial condition, results of operations and prospects.

Delays in business operations could adversely affect the market price of the Common Shares

Delays in business operations could adversely affect the market price of our Common Shares. In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of our properties, and the delays of those operators in remitting payment to us, payments between any of these parties may also be delayed by:

- restrictions imposed by lenders;
- accounting delays;
- delays in the sale or delivery of products;
- delays in the connection of wells to a gathering system;
- restrictions due to limited pipeline or processing capacity;
- operational problems affecting pipelines and facilities;
- blowouts or other accidents;
- adjustments for prior periods;
- recovery by the operator of expenses incurred in the operation of the properties; or
- the establishment by the operator of reserves for these expenses.

Any of these delays could expose us to additional third party credit risks.

The marketability of petroleum and natural gas that may be acquired or discovered by us will be affected by numerous factors beyond our control

These factors include demand for petroleum and natural gas, market fluctuations, the availability, proximity and capacity of oil and natural gas pipelines and processing and storage facilities and government regulations, including regulations relating to environmental protection, royalties, allowable production, pricing, taxes, importing and exporting of oil and natural gas and political events throughout the world that cause disruptions in the supply of oil and affect the marketability and price of oil and natural gas acquired or discovered by us. Any particular event could result in a material decline in prices and, therefore, result in a reduction of our net production revenue. The availability of markets is beyond our control. In addition, our oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of our properties, wells or facilities are the subject of terrorist attack it could have a material adverse effect on our financial condition. We do not have insurance to protect against the risk from terrorism.

Our existing Credit Agreement and any replacement credit facilities may not provide sufficient liquidity

Our existing Credit Agreement and any replacement credit facilities may not provide sufficient liquidity. The amounts available under our existing Credit Agreement may not be sufficient for future operations, or we may not be able to obtain additional financing on economic terms attractive to us, if at all. Our current Credit Agreement includes credit facilities in the maximum principal amount of $88 million. Our current Credit Agreement has a term date of June 22, 2016 and may be extended for a further 364-day period at our request. If the credit facilities are not extended, they convert to a 365-day term loan and are repayable in full at the end of such term. Repayment of all outstanding amounts under the Credit Agreement may be demanded on relatively short notice if an event of default occurs, which is continuing. If this occurs, we may need to obtain alternate financing. Any failure to obtain suitable replacement financing may have a material adverse effect on our business. There is also a risk that the Credit Agreement will not be extended for the same amount or on the same terms.

We are required to comply with covenants under the Credit Agreement. In the event that we do not comply with these covenants, which may be affected by events beyond our control, our access to capital could be restricted or repayment could be required on an accelerated basis by our lenders. The lenders under the Credit Agreement have security over all of our assets. If we become unable to pay our debt service charges or otherwise commit an event of default, the lenders under the Credit Agreement may foreclose on or sell our working interests in our properties.

If any of our lenders require repayment of all or portion of the amounts outstanding under our loans for any reason, including for a default of a covenant, there is no certainty that we would be in a position to make such repayment. Given the current market conditions and the lack of confidence in the Canadian oil and gas industry, we may have difficulty raising additional funds or if it we are able to do so, it may be on unfavourable and highly dilutive terms.

Our borrowing base is determined and re-determined by our lenders based on our reserves, commodity prices, applicable discount rate and other factors as determined by our lenders. Commodity prices continue to be depressed and have fallen dramatically since 2014. There remains a substantial amount of uncertainty as to when and if commodity prices will recover. Depressed commodity prices could reduce our borrowing base, thereby reducing the funds available to us under our credit facilities which could result in a portion, or all, of our indebtedness being required to be repaid.

Hydraulic fracturing is subject to certain risks

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 natural gas and oil from reservoirs that were previously unproductive. We use hydraulic fracturing extensively in our operations. With the increase in the use of fracture stimulations in horizontal wells there is increased communication between the oil and natural gas industry and a wider variety of stakeholders regarding the responsible use of this technology as it relates to the environment. This increased attention to fracture stimulations may result in increased regulation or changes of law which may make the conduct of our business more expensive or prevent us from conducting our business as currently conducted. Any new laws, regulation or permitting requirements regarding hydraulic fracturing could lead to operational delays or increased operating costs, third party or governmental claims, and could increase our 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 we are ultimately able to produce from our reserves.

Changes in government regulations that affect the oil and natural gas industry could adversely affect us

Government regulations may change from time to time in response to economic or political conditions. The exercise of discretion by governmental authorities under existing regulations, the implementation of new regulations or the modification of existing regulations affecting the oil and gas industry could reduce demand for crude oil and natural gas, increase our costs, or delay or restrict our operations, all of which would have a material adverse impact on us.

There can be no assurance that the federal government and the provincial governments of the western provinces will not adopt a new or modify the royalty regime which may have an impact on the economics of our projects. An increase in royalties would reduce our earnings and could make future capital investments, or our operations, less economic. See "*Industry Conditions*".

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 March 31, 2016. See "*Industry Conditions - Royalties and Incentives*".

Income tax laws or other laws or government incentive programs or regulations relating to our industry may in the future be changed or interpreted in a manner that adversely affects us and our Shareholders

Changes in tax and other laws may adversely affect Shareholders. Income tax laws, other laws or government incentive programs relating to the oil and natural gas industry, such as resource allowance, may in the future be changed or interpreted in a manner that adversely affects us and our Shareholders. Tax authorities having jurisdiction over us or our Shareholders may disagree with the manner in which we calculate our income for tax purposes or could change their administrative practices to our detriment or the detriment of Shareholders.

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation, and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada, Alberta, Saskatchewan and the United States, all of which should be carefully considered by investors in the oil and natural gas industry. All of such controls, regulations and legislation are subject to revocation, amendment or administrative change, some of which have historically been material and in some cases materially adverse and there can be no assurance that there will not be further revocation, amendment or administrative change which will be materially adverse to our assets, reserves, financial condition or results of operations or prospects.

We cannot assure you that income tax laws and government incentive programs relating to the oil and natural gas industry will not change in a manner that adversely affects the market price of the Common Shares.

We file all required income tax returns and believe that we are 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 us, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

Climate change laws and related environmental, health and safety regulation may impose restrictions or costs on our business which may adversely affect our financial condition

Our exploration and production facilities and other operations and activities emit greenhouse gases which may require the Corporation to comply with greenhouse gas emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the United Nations Framework Convention on Climate Change and a participant to the Copenhagen Agreement (a non-binding agreement created by the United Nations Framework Convention on Climate Change), the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction in greenhouse gas emissions from 2005 levels by 2020; however, these greenhouse gas 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 greenhouse gas emissions. As a result of the United Nations Framework Convention on Climate Change adopting the Paris Agreement on December 12, 2015, to which Canada was a participant, the Government of Canada is expected to announce a plan to further reduce its greenhouse gas emission reduction targets. The direct or indirect costs of compliance with these regulations may have a material adverse effect on our 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 greenhouse gas and resulting requirements, it is not possible to predict the impact us and our operations and financial condition. See "*Industry Conditions – Climate Change Regulation*".

Although we believe that we are in material compliance with current applicable environmental, health and safety regulations, no assurance can be given that such regulations will not result in a curtailment of production, a reduction of product demand, a material increase in the costs of production, development or exploration activities or otherwise adversely affect our business, financial condition, results of operations or prospects. Future changes in other environmental, health and safety legislation could occur and result in stricter standards and enforcement, larger fines and liability, and increased capital expenditures and operating costs, which could have a material adverse effect on our financial condition or results of operations and prospects. See "*Industry Conditions – Environmental Regulation*".

We may not be able to realize the anticipated benefits of acquisitions and dispositions or to manage growth

We make acquisitions and dispositions of businesses and assets in the ordinary course of our business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and our ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with our operations. The integration of acquired business 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. There is no assurance that we will be able to continue to complete acquisitions or dispositions of oil and natural gas properties which realize all the synergistic benefits.

We periodically dispose of non-core assets so that we can focus our efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain of our non-core assets, if disposed of, may realize less than their carrying value on our financial statements.

The price we pay for the purchase of any material properties is based on several criteria, including engineering and economic assessments made by independent engineers modified to reflect our technical and economic views. These assessments include a series of assumptions regarding such factors as recoverability and marketability of petroleum and natural gas, future prices of petroleum and natural gas and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond our control. All such assessments involve a measure of geologic and engineering uncertainty which could result in lower than anticipated production and reserves. Consequently, the reserves acquired may be less than expected, which could adversely impact cash flow from operating activities.

We may be subject to growth-related risks including capacity constraints and pressure on our internal systems and controls. Our ability to manage growth effectively will require us to continue to implement and improve our operational and financial systems and to expand, train and manage our employee base. Our inability to deal with this growth could have a material adverse effect on our business, financial condition, results of operations and prospects.

There is strong competition relating to all aspects of the oil and natural gas industry

There are numerous companies in the oil and natural gas industry, who are competing with us for the acquisitions of properties with longer life reserves, properties with exploitation and development opportunities and undeveloped land. As a result of such competition, it may be more difficult for us to acquire reserves on beneficial terms. Many of these other organizations have significantly greater technical, financial and operational resources than us.

We compete with other oil and gas companies to hire and retain skilled personnel necessary for running our daily operations, including planning, capitalizing on available technical advances and the execution of our exploration and development program. The inability to hire and retain skilled personnel could adversely impact certain of our operational and financial results.

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 us and may delay exploration and development activities.

The oil industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other oil companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before us. There can be no assurance that we 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 us or implemented in the future may become obsolete. In such case, our business, financial condition and results of operations could be materially adversely affected. If we are unable to utilize the most advanced commercially available technology, our business, financial condition and results of operations could be materially adversely affected.

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

Our petroleum and natural gas reserves are a depleting resource and decline as such reserves are produced

Absent commodity price increases or cost effective acquisition and development activities, our funds from operations will decline over time in a manner consistent with declining production from typical petroleum and natural gas reserves. Our future petroleum and natural gas reserves and production, and therefore our funds from operations, will be highly dependent on our success in exploiting our reserves base and acquiring additional reserves. Without reserves additions through acquisition or development activities, our reserves and production may decline over time as reserves are produced.

If external sources of capital, including the issuance of additional Common Shares, become limited or unavailable on commercially reasonable terms, our ability to make the necessary capital investments to maintain or expand our petroleum and natural gas reserves may be impaired. To the extent that we use funds from operations to finance capital expenditures or property acquisitions, the level of funds from operations available for distribution to Shareholders will be reduced. There can be no assurance that we will be successful in developing or acquiring additional reserves on terms that meet our investment objectives.

We may participate in larger projects and may have more concentrated risk in certain areas of our operations

We manage a variety of small and large projects in the conduct of our business. Project delays may impact expected revenues from operations. Significant project cost over runs could make a project uneconomic. Our ability to execute projects and market oil and natural gas depends upon numerous factors beyond our 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 our ability to dispose of water used or removed from strata at a reasonable cost and within applicable environmental regulations;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;

- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, we could be unable to execute projects on time, on budget or at all, and may be unable to effectively market the oil and natural gas that we produce effectively.

We only operate in western Canada and the United States and expansion outside of these areas may increase our risk exposure

Our operations and expertise are currently primarily focused on oil and gas production and development in the Western Canadian Sedimentary Basin and the United States. In the future we 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 our exposure to one or more existing risk factors, which may in turn result in our future operational and financial conditions being adversely affected.

Our success depends in large measure on the activities of our key personnel

Our Shareholders are entirely dependent on our management with respect to the acquisition of oil and gas properties, the development and acquisition of additional reserves, the management and administration of all matters relating to our properties, including the safekeeping of our primary workspace and computer systems. The loss of the services of key personnel may have a material adverse effect on our business, financial condition, results of operations and prospects. The contributions of the existing management team to our immediate and near term operations 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 we will be able to continue to attract and retain all personnel necessary for the development and operation of our business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of our management.

Securing and maintaining title to our properties is subject to certain risks

Our properties are held in the form of licenses and leases and working interests in licenses and leases. If we or the holder of the license or lease fails to meet the specific requirement of a license or lease, the license or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each license or lease will be met. The termination or expiration of a license or lease or the working interest relating to a license or lease may have a material adverse affect on our results of operations and business. In addition title to the properties can become subject to dispute and defeat our claim to title over certain of our properties.

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada and have also made claims that certain developments, including oil and gas exploration and development, may have been proceeding without the Crown carrying out appropriate consultations in the course of allowing such developments to proceed. We are not aware of any material claims having been made in respect of our properties and assets; however, if a claim arose and was successful this may have a material adverse affect on our results of operations and business.

Although title reviews are conducted prior to any purchase of significant resource assets, such reviews cannot guarantee that an unforeseen defect in the chain of title will not arise to defeat our title to certain assets. Our actual interest in properties may, therefore, vary from our records. If a title defect does exist, it is possible that we may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on our business, financial condition, results of operations and prospects. There may be valid challenges to title, or proposed legislative changes which affect title, to the oil and natural gas properties that we control that, if successful or made into law, could impair our activities on them and result in a reduction in the amount of funds from operations, which could result in a lower market price of the Common Shares.

We are affected by seasonality

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

Our permitted investments may be risky

An investment in us should be made with the understanding that the value of any of our investments may fluctuate in accordance with changes in the financial condition of such investments, the value of similar securities, and other factors. For example, the prices of Canadian government securities, bankers' acceptances and commercial paper react to economic developments and changes in interest rates. Commercial paper is also subject to issuer credit risk. Investments in energy related companies and partnerships will be subject to the general risks of investing in equity securities. These include the risk that the financial condition of issuers may become impaired, or that the energy sector may suffer a market downturn. Securities markets in general are affected by a variety of factors, including governmental, environmental and regulatory policies, inflation and interest rates, economic cycles, and global, regional and national events. The value of our Common Shares could be affected by adverse changes in the market values of such investments.

A shortfall in the supply of diluent may increase our costs

Heavy oil and bitumen are characterized by high specific gravity or weight and high viscosity or resistance to flow. Diluent is required to facilitate the transportation of heavy oil and bitumen. A shortfall in the supply of diluent may cause its price to increase thereby increasing the cost to transport heavy oil and bitumen to market and correspondingly increasing our overall operating cost, decreasing our net revenues and negatively impacting the overall profitability of our heavy oil and bitumen projects.

We may become involved in, named as a party to, or be the subject of, various legal proceedings

In the normal course of our operations, we 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 us and as a result, could have a material adverse effect on our assets, liabilities, business, financial condition and results of operations.

In addition, due to the rapid development of oil and gas technology, in the normal course of our operations, we may become involved in, named as a party to, or be the subject of, various legal proceedings in which it is alleged that we have infringed the intellectual property rights of others or commence lawsuits against others who we believe are infringing upon our rights. Our involvement in intellectual property litigation could result in significant expense, adversely affecting the development of our assets or intellectual property or diverting the efforts of our technical and management personnel, whether or not such litigation is resolved in our favour. In the event of an adverse outcome as a defendant in any such litigation, we may, among other things, be required to: (a) pay substantial damages; cease the development, use, sale or importation of process that infringe upon other patented intellectual property; (b) expend significant resources to develop or acquire non-infringing intellectual property; (c) discontinue processes incorporating infringing technology; or (d) obtain licences to the infringing intellectual property. We may not be successful in such development or acquisition or that such licences would be available on reasonable terms. Any such development, acquisition or licence could require the expenditure of substantial time and other/ resources and could have a material adverse effect on our business and financial results.

While discussing potential business relationships or other transactions with third parties, we may disclose confidential information relating to our business, operations or affairs. Although confidentiality agreements are signed by third parties prior to the disclosure of any confidential information, a breach could put us at competitive risk and may cause significant damage to our business. The harm to our 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, we 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.

Risks Relating to Ownership of Common Shares

Our Board of Directors has discretion in the payment of dividends

On November 11, 2015, as a result of volatile, uncertain and exceptionally low oil prices, we suspended our monthly dividend until further notice The amount of future cash dividends, if any, will be subject to the discretion of our Board of Directors and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by the *Business Corporations Act* (Alberta) for the declaration and payment of dividends. Depending on these and various other factors, many of which will be beyond the control of our Board of Directors and management team, we will change our dividend policy from time to time and, as a result, any future cash dividends could be reduced or suspended entirely. The future treatment of dividends for tax purposes will be subject to the nature and composition of our dividends and potential legislative and regulatory changes.

Changes in market-based factors may adversely affect the trading price of the 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 our performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices or current perceptions of the oil and gas market. Similarly, the market price of our Common Shares could be subject to significant fluctuations in response to variations in our operating results, financial condition, liquidity and other internal factors. The price at which our Common Shares will trade cannot be accurately predicted.

Certain Risks for United States and Other Non-Resident Shareholders

The ability of investors resident in the United States to enforce civil remedies is limited

We are a corporation incorporated under the laws of the Province of Alberta, Canada and our principal office is located in Calgary, Alberta. All of our directors and officers and the representatives of the experts who provide services to us (such as our auditors and our independent reserve engineers), and all or a substantial portion of our assets and the assets of such persons are located outside the United States. As a result, it may be difficult for investors in the United States to effect service of process within the United States upon such directors, officers and representatives of experts who are not residents of the United States or to enforce against them judgements of the United States courts based upon civil liability under the United States federal securities laws or the securities laws of any state within the United States. There is doubt as to the enforceability in Canada against us or any of our directors, officers or representatives of experts who are not residents of the United States, in original actions or in actions for enforcement of judgements of United States courts of liabilities based solely upon the United States federal securities laws or securities laws of any state within the United States.

Canadian and United States practices differ in reporting reserves and production and our estimates may not be comparable to those of companies in the United States

We report our production and reserve quantities in accordance with Canadian practices and specifically in accordance with NI 51-101. These practices are different from the practices used to report production and to estimate reserves in reports and other materials filed with the SEC by companies in the United States.

We incorporate additional information with respect to production and reserves which is either not required to be included or prohibited under rules of the SEC and practices in the United States. We follow the Canadian practice of reporting gross production and reserve volumes (before deduction of Crown and other royalties); however, we also follow the United States practice of separately reporting reserve volumes on a net basis (after the deduction of royalties and similar payments). We also follow the Canadian practice of using forecast prices and costs when we estimate our reserves; whereas the SEC rules require that a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, be utilized.

We included in this Annual Information Form estimates of proved and proved plus probable reserves. Probable reserves have a lower certainty of recovery than proved reserves. The SEC requires oil and gas issuers in their filings with the SEC to disclose only proved reserves but permits the optional disclosure of probable reserves. The SEC definitions of proved reserves and probable reserves are different than NI 51-101; therefore, proved, probable and proved plus probable reserves disclosed in this Annual Information Form may not be comparable to United States standards.

As a consequence of the foregoing, our reserve estimates and production volumes in this Annual Information Form may not be comparable to those made by companies utilizing United States reporting and disclosure standards.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contract entered into by us within the most recently completed financial year, or before the most recently completed financial year but which is still material and is in effect, are as follows:

1. our Credit Agreement in respect of our $88 million syndicated credit facilities, which agreement is described in Note 10 to our annual audited consolidated financial statements for the year ended December 31, 2015, which note is incorporated by reference herein; and

2. the Debenture Indenture.

Copies of each of these documents have been filed on SEDAR at www.sedar.com.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings that we are or were a party to, or that any of our property is or was the subject of, during the most recently completed financial year, that were or are material to us, and there are no such material legal proceedings that we are currently aware of that are contemplated.

There were no: (i) penalties or sanctions imposed against us by a court relating to securities legislation or by a securities regulatory authority during our most recently completed financial year; (ii) other penalties or sanctions imposed by a court or regulatory body against us that would likely be considered important to a reasonable investor in making an investment decision; or (iii) settlement agreements we entered into with a court relating to securities legislation or with a securities regulatory authority during our most recently completed financial year.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for our Common Shares is Computershare Trust Company of Canada at its principal offices in Calgary, Alberta and Toronto, Ontario.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of our directors and senior officers, any holder of Common Shares who beneficially owns, or controls or directs, directly or indirectly, more than 10 percent of the outstanding Common Shares, or any known associate or affiliate of such persons, in any transaction within the last three financial years or during the current financial year which has materially affected or would materially affect us.

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 report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under National Instrument 51-102 – Continuous Disclosure Obligations by us during, or related to, our most recently completed financial year other than McDaniel, our independent engineering evaluator, and Ernst & Young LLP, our auditors.

None of the "designated professionals" (as that term is defined in National Instrument 51-102) of McDaniel had any registered or beneficial interests, direct or indirect, in any of our securities or other property or of our associates or affiliates either at the time they prepared the report, valuation, statement or opinion prepared by it, at any time thereafter or to be received by them.

Ernst & Young LLP is independent in accordance with the Rules of Professional Conduct as outlined by the Chartered Professional Accountants of Alberta.

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 us or of any of our associate or affiliate entities, except that Grant A. Zawalsky, one of our directors, is a partner at Burnet, Duckworth & Palmer LLP, which is a law firm that renders legal services to us.

ADDITIONAL INFORMATION

Additional information relating to us can be found on SEDAR at www.sedar.com and on our website at www.zargon.ca. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities issued and authorized for issuance under our equity compensation plans are contained in our information circular – proxy statement dated April 14, 2016 relating to our annual Shareholders meeting to be held on May 30, 2016. Additional financial information is contained in our consolidated financial statements for the year ended December 31, 2015 and the related management's discussion and analysis.

For additional copies of the Annual Information Form and the materials listed in the preceding paragraphs please contact:

Zargon Oil & Gas Ltd.
700, 333 – 5th Avenue S.W.
Calgary, Alberta, T2P 3B6
Tel: (403) 264-9992
Fax: (403) 265-3026

APPENDIX A

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

(Form 51-101F3)

Management of Zargon Oil & Gas Ltd. ("**Zargon**") is responsible for the preparation and disclosure of information with respect to Zargon's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

An independent qualified reserves evaluator has evaluated Zargon's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Audit and Reserves Committee of the board of directors of Zargon has

(a) reviewed Zargon's procedures for providing information to the independent qualified reserves evaluator;

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

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

The Audit and Reserves Committee of the board of directors has reviewed Zargon'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 Audit and Reserves Committee, approved

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

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data, contingent resources data or prospective resources data; and

(c) the content and filing of this report.

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

(signed) C.H. Hansen
President and Chief Executive Officer

(signed) B.G. Kergan
Vice President, Corporate Development

(signed) K.D. Kitagawa
Director and Member of the Audit and Reserves Committee

(signed) G.C. Merritt
Director and Member of the Audit and Reserves Committee

January 21, 2016

APPENDIX B

REPORT ON RESERVES DATA BY MCDANIEL

(Form 51-101F2)

To the board of directors of Zargon Oil & Gas Ltd. ("**Zargon**"):

1. We have evaluated Zargon'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 Zargon'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 net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of Zargon evaluated for the year ended December 31, 2015, and identifies the respective portions thereof that we have evaluated and reported on to Zargon's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue (thousands before income taxes, 10% discount rate)			
			Audited	**Evaluated**	**Reviewed**	**Total**
McDaniel & Associates Consultants Ltd.	December 31, 2015	Canada	$nil	$232,662	$nil	$232,662
		United States	$nil	$26,636	$nil	$26,636

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 report referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.

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

Executed as to our report referred to above:

(signed) McDaniel & Associates Consultants Ltd.
Calgary, Alberta, Canada

January 21, 2016

APPENDIX C

MANDATE & TERMS OF REFERENCE OF THE AUDIT AND RESERVES COMMITTEE

Role and Objective

The Audit and Reserves Committee (the "**Committee**") is appointed by the Board of Directors (the "**Board**") of Zargon Oil & Gas Ltd. ("**Zargon**" or the "**Corporation**"), to which the Board has delegated its responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements, the audited financial statements and other mandatory disclosure releases containing financial information, and reviewing the annual independent report of the Corporation's petroleum and natural gas reserves and recommending all, for board of director approval.

Membership of Committee

1. The Committee shall be comprised of at least three (3) directors of Zargon, none of whom are members of management of Zargon and all of whom are "independent" (as such term is used in Multilateral Instrument 52-110 - *Audit Committees* ("**MI 52-110**") and National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**"). Committee members shall also meet the independence requirements of the regulatory bodies to which the Corporation may be subject to.

2. All of the members of the Committee shall be "financially literate". The Board has adopted the definition for "financial literacy" used in MI 52-110.

3. The Board may from time to time designate one of the members of the Committee to be the Chair of the Committee.

Mandate and Responsibilities of Committee

1. The Committee shall, in addition to any other duties and responsibilities specifically delegated to it by the Board, generally assume responsibility for developing the approach of the Corporation to matters concerning all financial information and disclosure and all petroleum and natural gas reserves information and disclosure and, from time to time, shall review and make recommendations to the Board as to such matters. Specifically, the Committee will have the authority and responsibility for:

    (a) Audit Matters:

    (i) To assist directors meet their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of Zargon and related matters;

    (ii) To provide better communication between directors and external auditors;

    (iii) To enhance the external auditor's independence;

    (iv) To increase the credibility and objectivity of financial reports;

    (v) To strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors;

    (vi) It is the responsibility of the Committee to oversee the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting;

(vii) It is the responsibility of the Committee to satisfy itself on behalf of the board with respect to Zargon's Internal Control Systems:

A. Identifying, monitoring and mitigating business risks; and

B. Ensuring compliance with legal, ethical and regulatory requirements.

(viii) It is a primary responsibility of the Committee to review the annual financial statements of Zargon prior to their submission to the board of directors for approval. The process should include but not be limited to:

A. Reviewing changes in accounting principles, or in their application, which may have a material impact on the current or future years' financial statements;

B. Reviewing significant accruals, reserves or other estimates such as the impairment test calculation;

C. Reviewing accounting treatment of unusual or non-recurring transactions;

D. Ascertaining compliance with covenants under loan agreements;

E. Reviewing disclosure requirements for commitments and contingencies;

F. Reviewing adjustments raised by the external auditors, whether or not included in the financial statements;

G. Reviewing unresolved differences between management and the external auditors; and

H. Obtain explanations of significant variances with comparative reporting periods.

(ix) The Committee is to review the financial statements, prospectuses, management discussion and analysis ("**MD&A**"), annual information forms ("**AIF**") and all public disclosure containing audited or unaudited financial information before release and prior to board approval. The Committee must be satisfied that adequate procedures are in place for the review of Zargon's disclosure of all other financial information and shall periodically access the accuracy of those procedures.

(x) With respect to the appointment of external auditors by the board, the Committee shall:

A. Recommend to the board the appointment of the external auditors;

B. Recommend to the board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors shall report directly to the Committee;

C. When there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and

D. Review and approve any non-audit services to be provided by the external auditors' firm and consider the impact on the independence of the auditors.

(xi) Review with external auditors (and internal auditor if one is appointed by Zargon) their assessment of the internal controls of Zargon, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee shall also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Zargon and its subsidiaries.

(xii) The Committee must pre–approve all non–audit services to be provided to Zargon or its subsidiaries by the external auditors. The Committee may delegate to one or more members the authority to pre–approve non–audit services, provided that the member report to the Committee at the next scheduled meeting such pre–approval and the member comply with such other procedures as may be established by the Committee from time to time.

(xiii) The Committee shall review risk management policies and procedures of Zargon (i.e. hedging, litigation and insurance).

(xiv) The Committee shall establish a procedure for:

A. The receipt, retention and treatment of complaints received by Zargon regarding accounting, internal accounting controls or auditing matters; and

B. The confidential, anonymous submission by employees of Zargon of concerns regarding questionable accounting or auditing matters.

(xv) The Committee shall review and approve Zargon's hiring policies regarding employees and former employees of the present and former external auditors of Zargon.

(xvi) The Committee shall have the authority to investigate any financial activity of Zargon. All employees of Zargon are to cooperate as requested by the Committee.

(xvii) The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in filling their responsibilities at the expense of Zargon without any further approval of the board.

(b) Reserves Matters:

(i) In conjunction with the Corporation's senior engineering management, meet with the independent evaluating engineers being considered for appointment to review their qualifications and independence to ensure the independent evaluating engineers being considered for appointment are technically qualified and competent, are independent of management and to establish the terms of their engagement;

(ii) After consultation with the Corporation's senior engineering management recommend to the Board the appointment of the independent evaluating engineers to assist the Corporation in the annual review of its petroleum and natural gas reserves;

(iii) In consultation with the Corporation's senior engineering management determine the scope of the annual review of the petroleum and natural gas reserves by the independent evaluating engineers, having regard to regulatory reporting requirements;

(iv) Review both the procedures for providing petroleum and natural gas reserves information to the independent evaluating engineers and the information used by the independent evaluating engineers to enable the independent evaluating engineers to provide a report that will meet regulatory reporting requirements;

(v) In consultation with the Corporation's senior engineering management and the independent evaluating engineers:

A. Determine whether any restrictions affect the ability of the independent evaluating engineers to report on reserves data without reservations; and

B. Review the reserves data and the report of the independent evaluating engineers.

(vi) Recommend to the Board for filing, the report from the independent evaluating engineers and/or senior engineering management on the Corporation's petroleum and natural gas reserves data;

(vii) Ensure the disclosure to the public on the Corporation's petroleum and natural gas reserves is in compliance with regulatory requirements;

(viii) Review any proposals to change the independent evaluating engineers and/or resolve any differences between the independent evaluating engineers and management;

(ix) Meet on an annual basis with the Corporation's senior engineering management and/or the independent evaluating engineers of the Corporation to review and consider the evaluation of the Corporation’s petroleum and natural gas reserves;

(x) Meet separately with the independent evaluating engineers and/or senior engineering management when the Committee deems it desirable and advise the Board on the results of such meeting; and

(xi) Co-ordinate meetings with the Corporation's senior engineering management, independent evaluating engineers and auditors as required to address matters of mutual concern in respect of the Corporation’s evaluation of petroleum and natural gas reserves.

Meeting and Administrative Matters

1. Meetings of the Committee should be scheduled to take place at least four (4) times per year. Special meetings may be convened as required upon the request of the Committee Chairman or the CEO. The President and Chief Executive Officer and the Chief Financial Officer shall attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman

2. A majority of the members of the Committee shall constitute a quorum. No business may be transacted by the Committee except at a meeting of its members at which a quorum of the Committee is present or by a resolution in writing signed by all the members of the Committee. Meetings may occur via telephone or teleconference

3. Any members of the Committee may be removed or replaced at any time by the Board and shall cease to be a member of the Committee as soon as such member ceases to be a director. The Board of Directors may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy shall exist on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, each member of the Committee shall hold such office until the close of the next annual meeting of shareholders following appointment as a member of the Committee

4. The Committee may invite such officers, directors and employees of the Corporation as it may see fit from time to time to attend at meetings of the Committee and assist thereat in the discussion and consideration of the matters being considered by the Committee

5. The time at which and place where the meetings of the Committee shall be held and the calling of meetings and the procedure in all respects at such meetings shall be determined by the Committee, unless otherwise determined by the by-laws of the Corporation or by resolution of the Board

6. Unless otherwise designated by the Board, the members of the Committee shall elect a Chairman from among the members and the Chairman shall preside at all meetings of the Committee. The Chairman of the Committee shall have a second and deciding vote in the event of a tie. In the absence of the Chairman, the members of the Committee shall appoint one of their members to act as Chairman. Notwithstanding the foregoing, in all circumstances the Chairman must be an outside director, unrelated to the Corporation

7. Minutes of the Committee will be recorded and maintained and circulated to directors who are not members of the Committee or otherwise made available at a subsequent meeting of the Board

8. Agendas, approved by the Chair, will be circulated to Committee members along with background information on a timely basis prior to the Committee meetings

9. The Committee may obtain information from any employee of the Corporation and the Corporation's agents that it may require to carry out this mandate. The Committee may retain persons having special expertise and may obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Corporation, as determined by the Committee

10. Any issues arising from these meetings that bear on the relationship between the Board and management should be communicated to the Chairman of the Board by the Committee Chair

11. The Committee shall meet with the external auditor at least once per year (in connection with the preparation of the yearend financial statements) and at such other times as the external auditor and the Committee consider appropriate

12. Review annually the Committee mandate and terms of reference and recommend any changes to the Board