**YOHO RESOURCES INC.**

**ANNUAL INFORMATION FORM**

**FOR THE FISCAL YEAR ENDED SEPTEMBER 30, 2015**

**JANUARY 13, 2016**

## TABLE OF CONTENTS

**Page**


ABBREVIATIONS AND CONVERSIONS....1
SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS....2
CERTAIN DEFINITIONS....3
CONVENTIONS....5
CORPORATE STRUCTURE....5
GENERAL DEVELOPMENT OF OUR BUSINESS....7
DESCRIPTION OF THE BUSINESS AND OPERATIONS....8
SIGNIFICANT ACQUISITIONS....10
STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION....10
MATERIAL CHANGES TO RESERVES INFORMATION....18
PRO-FORMA RESERVES INFORMATION....19
ADDITIONAL INFORMATION RELATING TO RESERVES DATA....20
OTHER OIL AND GAS INFORMATION....22
INDUSTRY CONDITIONS....27
RISK FACTORS....40
DIRECTORS AND OFFICERS....53
YOHO SHARE CAPITAL....55
DIVIDEND POLICY....55
MARKET FOR SECURITIES....55
ESCROWED SECURITIES....56
LEGAL PROCEEDINGS AND REGULATORY ACTIONS....56
INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS....56
AUDITORS, TRANSFER AGENT AND REGISTRAR....56
INTERESTS OF EXPERTS....57
MATERIAL CONTRACTS....57
ADDITIONAL INFORMATION....57

**APPENDIX "A"** FORM 51-101F2 REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

**APPENDIX "B"** FORM 51-101F3 REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

## ABBREVIATIONS AND CONVERSIONS

**Oil and Natural Gas Liquids**

| | |
|---|---|
| Bbl | Barrel |
| MBbl | thousand barrels |
| bbl/d | barrels per day |
| NGLs | natural gas liquids |

**Natural Gas**

| | |
|---|---|
| Mcf | thousand cubic feet |
| MMcf | million cubic feet |
| Mcf/d | thousand cubic feet per day |
| MMbtu | million British Thermal Units |
| GJ | gigajoule |
| MM | Million |

**Other**

| | |
|---|---|
| AECO | A natural gas storage facility located at Suffield, Alberta. |
| API | American Petroleum Institute |
| °API | an indication of the specific gravity of crude oil measured on the API gravity scale. |
| boe | barrel of oil equivalent of natural gas and crude oil on the basis of 1 BOE for 6 Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices) |
| boe/d | barrel of oil equivalent per day |
| $Cdn | Canadian dollars |
| $m^3$ | cubic metres |
| Mcfe | means 1,000 cubic feet equivalent on the basis of 1 one Bbl of crude oil for 6 Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices) |
| Mboe | 1,000 barrels of oil equivalent |
| M$ | thousands of dollars |
| $US | United States dollars |
| WTI | West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade |

**Disclosure provided herein in respect of boes 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. Given the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6 mcf: 1 bbl, utilizing a conversion ratio of 6 mcf: 1 bbl may be a misleading indication of value.**

**Disclosure provided herein in respect of Mcfe may be misleading, particularly if used in isolation. The Mcfe conversion ratio of one Bbl of oil to six thousand cubic feet of gas used throughout this document is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.**

Where any disclosure of reserves data is made in this annual information form that does not reflect all reserves of Yoho, the reader should note that the estimates of reserves and future net revenue for individual properties or groups of 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.

| To Convert From | To | Multiply By |
|---|---|---|
| Mcf | cubic meters | 28.174 |
| cubic meters | cubic feet | 35.494 |
| bbl | cubic meters | 0.159 |
| cubic meters | bbl oil | 6.290 |
| feet | meters | 0.305 |
| meters | feet | 3.281 |
| miles | kilometers | 1.609 |
| kilometers | miles | 0.621 |
| acres (Alberta) | hectares | 0.400 |
| hectares (Alberta) | acres | 2.500 |

## SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS

Certain of the statements contained herein including, without limitation, financial and business prospects and financial outlook, reserve and production estimates, drilling plans, activities to be undertaken in various areas, timing of drilling, recompletion and tie-in of wells, tax horizon, timing of development of undeveloped reserves, planned capital expenditures, the timing thereof and the method of funding may be forward looking statements which reflect management's expectations regarding future plans and intentions, growth, results of operations, performance and business prospects and opportunities. Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and similar expressions have been used to identify these forward looking statements. These statements reflect management's current beliefs and are based on information currently available to management. Forward looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward looking statements including, but not limited to, changes in general economic and market conditions, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources and risk factors outlined under "Risk Factors" and elsewhere herein. The recovery and reserve estimates of Yoho's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

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

Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect Yoho's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com), and at Yoho's website (www.yohoresources.ca). Although the forward looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward looking statements. Investors should not place undue reliance on forward looking statements.

These forward looking statements are made as of the date hereof and the Corporation assumes no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

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

## CERTAIN DEFINITIONS

In this Annual Information Form, the following words and phrases have the following meanings, unless the context otherwise requires:

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

"**2004 Arrangement**" means the reorganization transaction which closed on December 23, 2004 pursuant to a plan of arrangement under the provisions of subsection 183(1) of the *Business Corporations Act* (Ontario) as fully described under the heading "Corporate Structure – Incorporation" herein;

"**2014 Arrangement**" means the plan of arrangement completed by Yoho on March 20, 2014 under the provisions of the ABCA among Yoho, Yoho Resources Partnership and the shareholders of Yoho as fully described under the heading "Corporate Structure – Incorporation" herein.

"**Canoil**" means Canoil Inc., a corporation which was incorporated pursuant to the ABCA and which was amalgamated with Yoho on July 30, 2010;

"**Class B Non-Voting Common Shares**" means the non-voting common shares created on February 28, 2007, on the conversion of the Non-Voting Common Shares into Common Shares and Class B Non-Voting Common Shares on the basis of 0.4 of a Common Share and 0.6 of a Class B Non-Voting Common Share for every one (1) Non-Voting Common Share which Class B Non-Voting Common Shares were subsequently cancelled on March 11, 2008;

"**Class C Non-Voting Common Shares**" means the non-voting common shares created on March 11, 2008 on the conversion of the Class B Non-Voting Common Shares into Common Shares and Class C Non-Voting Common Shares on the basis of 0.5 of a Common Share and 0.5 of a Class C Non-Voting Common Share for every one (1) Class B Non-Voting Common Share which Class C Non-Voting Common Shares were subsequently cancelled on February 10, 2009;

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

"**Corporation**", "**Yoho**", "**we**", "**us**" or "**our**" means Yoho Resources Inc. and all its controlled entities on a consolidated basis;

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

**"Debentures"** means the $11.8 million aggregate principal amount of 8.25% convertible secured subordinated debentures of the Corporation due June 30, 2020;

"**Development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground draining, road building, and relocating public roads, gas lines and power lines, pumping equipment and wellhead assembly;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems;

"**Exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells;

"**GLJ**" means GLJ Petroleum Consultants Ltd., independent petroleum consultants of Calgary, Alberta;

"**GLJ Report**" means the report prepared by GLJ November 18, 2015 entitled "Reserves Assessment and Evaluation of Canadian Oil and Gas Properties" evaluating the crude oil, natural gas liquids and natural gas resources of Yoho as of September 30, 2015;

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

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

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

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

"**JV Companies**" means 960330 Alberta Ltd., 960331 Alberta Ltd., 960332 Alberta Ltd., 960333 Alberta Ltd., 960334 Alberta Ltd., Atlee Joint Venture Ltd., Basset Lake Joint Venture Ltd.; Basset Lake III Joint Venture Ltd., Edam Joint Venture Ltd., Hamilton Lake III Joint Venture Ltd. and Sousa Joint Venture Ltd.;

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

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

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

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

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

"**Non-Voting Common Shares**" means the non-voting common shares of the Corporation created through the 2004 Arrangement on December 23, 2004 and subsequently cancelled on February 28, 2007;

"**Old Common Share**" means the voting common shares in the capital of the Corporation that were outstanding prior to the 2014 Arrangement;

"**TSXV**" means the TSX Venture Exchange;

"**United States**" or "**U.S.**" means the United States of America, its territories and possessions, any State of the United States, and the District of Columbia; and

"**Vision 2000**" means Vision 2000 Exploration Ltd., a corporation which was incorporated pursuant to the ABCA and which was amalgamated with Yoho on August 1, 2008.

**Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.**

Unless otherwise specified, information in this Annual Information Form is as at the end of the Corporation's most recently completed fiscal year, being the fiscal year ended September 30, 2014.

## CONVENTIONS

Certain terms used herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings in this Annual Information Form as in NI 51-101. Unless otherwise indicated, references in this Annual Information Form to "$" or "dollars" are to Canadian dollars. All financial information contained in this Annual Information Form has been presented in Canadian dollars in accordance with generally accepted accounting principles in Canada. Words importing the singular number only include the plural, and vice versa, and words importing any gender include all genders. All operational information contained in this Annual Information Form relates to our consolidated operations unless the context otherwise requires.

## CORPORATE STRUCTURE

### Incorporation

Yoho was incorporated pursuant to the laws of the Province of Alberta by certificate of incorporation on July 12, 1993 under the name Torque Industries Inc. On March 15, 1994, the Corporation acquired BCB Technology Group Inc., a private Ontario corporation, through a share exchange. By Articles of Amendment dated March 18, 1994, the name of the Corporation was changed to BCB Holdings Inc. By Articles of Continuance dated October 1, 1996, the Corporation was continued under the laws of Ontario. By Articles of Amendment dated August 17, 1998 and August 31, 1998, the Corporation changed its name to BCB Voice Systems Inc. and consolidated its common shares on a 10 for one (1) basis. By Articles of Amendment dated October 4, 2000 the Corporation changed its name to VoiceIQ Inc.

On December 23, 2004, Yoho closed the 2004 Arrangement pursuant to an arrangement agreement dated as of November 18, 2004 among the Corporation, VIQ Solutions Inc. and Yoho Resources Investment Partnership. Pursuant to the 2004 Arrangement, the Corporation divested its technology business and assets to its shareholders and changed its name to "Yoho Resources Inc." and changed its focus to developing an oil and gas exploration and production business. Articles of Arrangement of the Corporation were filed in Ontario effective December 23, 2004, changing the name of the Corporation to "Yoho Resources Inc." By Articles of Continuance dated December 24, 2004, the Corporation was continued under the laws of Alberta.

By Articles of Amendment dated February 28, 2007, Yoho reorganized its share capital to convert all of the outstanding Non-Voting Common Shares into Old Common Shares and Class B Non-Voting Common Shares on the basis of 0.4 of an Old Common Share and 0.6 of a Class B Non-Voting Common Share for every one (1) Non-Voting Common Share, and to delete the Non-Voting Common Shares as an authorized class of shares of the Corporation.

By Articles of Amendment dated March 11, 2008, Yoho reorganized its share capital to convert all of the outstanding Class B Non-Voting Common Shares into Old Common Shares and Class C Non-Voting Common Shares on the basis of 0.5 of an Old Common Share and 0.5 of a Class C Non-Voting Common Share for every one (1) Class B Non-Voting Common Share, and to delete the Class B Non-Voting Common Shares as an authorized class of shares of the Corporation.

By Articles of Amalgamation dated August 1, 2008, Yoho amalgamated with its wholly owned subsidiary, Vision 2000.

By Articles of Amendment dated February 10, 2009, Yoho reorganized its share capital to convert all of the outstanding Class C Non-Voting Common Shares into Old Common Shares on the basis of one (1) Old Common Share for every one (1) Class C Non-Voting Common Share, and to delete the Class C Non-Voting Common Shares as an authorized class of shares of the Corporation.

By Articles of Amalgamation dated July 30, 2010, Yoho amalgamated with its wholly owned subsidiary, Canoil.

On March 20, 2014, Yoho completed the 2014 Arrangement among Yoho, Yoho Resources Partnership and the shareholders of Yoho under the provisions of the ABCA. Pursuant to the 2014 Arrangement, each Old Common Share outstanding on March 20, 2014 was exchanged for one new Common Share in the capital of Yoho and 0.2591 of a common share ("**Storm Share**") in the capital of Storm Resources Ltd. ("**Storm**").

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

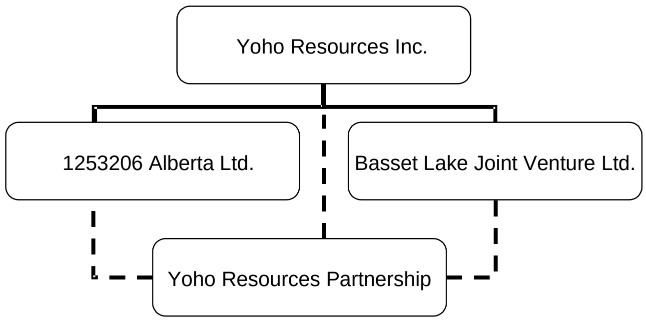
Yoho's head office is located at 500, 521 – 3rd Avenue SW, Calgary, Alberta T2P 3T3 and the registered office is located at 2400, 525 - 8th Avenue S.W., Calgary, Alberta T2P 1G1.

**Inter-Corporate Relationships**

The following table provides the name, the percentage of voting securities owned by us and the jurisdiction of incorporation of our subsidiaries as at the date hereof.

| | Percentage of voting securities (directly or indirectly) | Jurisdiction of Incorporation/ Organization |
|---|---|---|
| 1253206 Alberta Ltd. | 100% | Alberta |
| Basset Lake Joint Venture Ltd. | 100% | Alberta |
| Yoho Resources Partnership | 100% | Alberta |

The following diagram describes the inter-corporate relationships among us and our subsidiaries:




## GENERAL DEVELOPMENT OF OUR BUSINESS

Prior to the completion of the 2004 Arrangement, the Corporation carried out a technology related business, specifically a voice capture, digitization and compression business.

Upon completion of the 2004 Arrangement, Yoho became an oil and gas exploration, development and production company by acquiring the shares of the JV Companies, which resulted in the acquisition of oil and gas properties. Effective August 1, 2004, each of the JV Companies conveyed substantially all of their oil and gas related properties to Yoho Resources Partnership in return for a percentage interest in the capital of that partnership.

Yoho will continue to move forward with the unconventional resource style projects that we have been able to develop over the past two years. Complementary and accretive acquisitions may supplement the Corporation's exploration and development program when they can be accomplished on economic terms.

We fund our exploration and development program with cash flow, additional debt and strategic use of new equity as appropriate.

### Three Year History

***Year Ended September 30, 2013***

During the year ended September 30, 2013, Yoho continued the development of its Duvernay assets at Kaybob by drilling 2 gross (1.5 net) gas wells and constructed certain pipeline and facilities at Kaybob. Yoho also added to its land base at Kaybob with the acquisition in March 2013 of a 25% working interest in three sections of Duvernay rights. At Nig, British Columbia, Yoho closed an asset exchange transaction in March 2013 with its partner in the Nig lands whereby each party exchanged their 50% working interest in certain lands. As a result of this transaction, Yoho now holds 100% in 29 gas spacing units in the southern land block at Nig in exchange for the Corporation's interest in the northern land block at Nig.

***Year Ended September 30, 2014***

On November 4, 2013, Mr. Gregory Niebergall was appointed Vice President, Exploration of Yoho.

On January 31, 2014, Yoho completed the disposition of Yoho's Montney acreage in the Nig area of Northeast British Columbia held by Yoho's direct and indirect wholly owned subsidiary, Yoho Resources Partnership, to Storm for total consideration of approximately $87.7 million (the "**Transaction**"). Pursuant to the terms of an asset purchase and sale agreement dated January 22, 2014 among Yoho, Yoho Resources Partnership and Storm, Storm agreed to acquire the assets for total consideration of approximately $87.7 million, subject to customary adjustments, comprised of: (i) 13,629,442 Storm Shares with a deemed value at $4.23 per share, being the closing price for the Storm Shares on the TSXV on January 22, 2014; and (ii) $30 million in cash. The Storm Shares received as partial consideration from the Transaction were distributed to Yoho's shareholders pursuant to 2014 Arrangement on March 20, 2014. Pursuant to the 2014 Arrangement, each Old Common Share outstanding on March 20, 2014 was exchanged for one new Common Share and 0.2591 of a Storm Share.

***Year Ended September 30, 2015***

On June 16, 2015, the Corporation completed a brokered private placement whereby the Corporation issued: (i) 950,000 Common Shares at a price of $0.63 per share for total gross proceeds of $598,500; (ii) 7,562,300 Common Shares issued on a "flow-through" basis at a price of $0.68 per share for total gross proceeds $5,142,364; and (iii) $11.8 million aggregate principal amount of Debentures. The Debentures bear interest at a rate of 8.25% per annum, payable semi-annually on the last day of June and December commencing with the initial interest payment on December 31, 2015 and have a maturity date of June 30, 2020 and are secured by all present and after acquired property of the Corporation, subject to subordination to the Corporation's senior lender under its credit facility. The Debentures are convertible at the option of the holder to Common Shares at a conversion price of $0.78 per share. The Corporation has the option to redeem the Debentures on or after June 30, 2018 and at any time prior to June 30, 2020 at a redemption price equal to 100% of their principal amount plus accrued and unpaid interest, provided that the weighted average trading price of the Common Shares on the TSXV during the 20 consecutive trading days ending on the fifth trading day preceding the date on which the notice of redemption is given is not less than 125% of $0.78. The Debentures also require, in certain circumstances, including a "change of control" (including the sale of the majority of the Corporation's Duvernay assets) that the Corporation makes an offer to redeem the outstanding Debentures at a price equal to 120% of the principal amount thereof plus accrued and unpaid interest.

***Recent Developments***

On December 17, 2015, Yoho closed a transaction to sell approximately 75% of its net Duvernay acreage in the Kaybob area of Alberta for cash consideration of $50 million (prior to adjustments) (the "**Kaybob Duvernay Disposition**"). Subsequent to the Kaybob Duvernay Disposition, Yoho retained approximately 25% of its net Kaybob Duvernay acreage consisting of 5.5 sections at 100% working interest. See "*Material Changes to Reserves Information*". After the completion of Kaybob Duvernay Disposition, Yoho holds the following assets:

- 27 net sections (average working interest 90%) in the greater Inga area of British Columbia where the Corporation has a multi-zoned Triassic play, currently focused on the Montney Formation;
- 5.5 sections (100% working interest) of contiguous Duvernay land in Kaybob which have been continued by a recently completed well (16-12-59-19 W5); and
- Various other conventional assets.

On January 8, 2016, as a result of the Kaybob Duvernay Disposition, Yoho announced an offer to purchase, for cash, the outstanding Debentures at a price equal to 120% of their principal amounts plus accrued and unpaid interest. Such offer expires on February 12, 2016.

## DESCRIPTION OF THE BUSINESS AND OPERATIONS

### Business Plans and Growth Strategies

The business plan of Yoho is to create sustainable and profitable per share growth in reserves, production and cash flow in the oil and gas industry in Western Canada. To accomplish this, Yoho has pursued and will continue to pursue an integrated growth strategy with active development and exploration drilling, together with focused acquisitions. Yoho will continue to target areas and prospects that it believes could result in meaningful reserve and production additions.

Yoho will continue to move forward with the unconventional resource style projects that we have been able to develop over the past two years. Yoho will also continue to pursue internal generation of further unconventional resource style plays. Over the medium to long term, Yoho intends to enter into the development phase the Montney play in British Columbia, which targets natural gas reserves containing natural gas liquids. Management of Yoho considers asset and corporate acquisition opportunities from time to time that meet Yoho's business parameters.

Management of Yoho has industry experience in producing areas in western Canada in addition to its current geographic areas of interest and has the capability to expand the scope of Yoho's activities as opportunities arise.

In reviewing potential drilling or acquisition opportunities, Yoho gives consideration to the following criteria:

- Yoho's technical expertise in the opportunity;
- the amount of risk capital required to secure or evaluate the investment opportunity;
- the potential return on the project, if successful;
- the likelihood of success; and
- risked return versus cost of capital.

In general, Yoho intends to continue its pursuit of a portfolio approach in developing a large number of opportunities with a balance of risk profiles and commodity exposure in an attempt to generate sustainable high levels of growth.

The Board of Directors of Yoho may, in its discretion, approve asset or corporate acquisitions or investments that do not conform to the guidelines discussed above based upon the board's consideration of the qualitative aspects of the subject properties, including risk profile, technical upside, reserve life and asset quality.

**Specialized Skill and Knowledge**

The Corporation relies on specialized skills and knowledge to gather, interpret and process geophysical data; drill and complete wells; design and operate production facilities and numerous additional activities required to explore for and produce oil and natural gas. The Corporation has employed a strategy of contracting consultants and other service providers to supplement the skills and knowledge of its permanent staff in order to provide the specialized skills and knowledge to undertake its oil and natural gas operations effectively.

**Cyclical and Seasonal Nature of Industry**

The production of oil and natural gas reserves will be adversely affected by cold weather during winter months, potentially resulting in production down time due to mechanical failures arising from cold temperatures and the freezeup of production equipment and wellheads. These factors could result in lower than expected production during periods of extremely cold weather accompanied by higher than normal lease operating expenses. Exploration and development drilling in "winter-only access" areas are only possible during periods of cold weather, making the timing of drilling and tie-in of wells in "winter-only access" areas difficult to predict. Physical access for road construction, lease construction, drilling, facilities construction and pipeline construction is potentially affected by wet ground conditions arising during spring break-up and during periods of high rainfall making timing of projects uncertain.

Yoho's 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.

**Environmental Considerations**

The Corporation is subject to numerous environmental regulations including restrictions on where and when oil and gas operations can occur; regulations on the release of substances into groundwater, atmosphere and surface land and the routing of pipelines and location of production facilities. The Corporation is potentially liable for pre-existing contamination on properties acquired through acquisitions, and attempts to mitigate this risk by performing an environmental review during the due-diligence phase of an acquisition. Breach of environmental regulations can result in restrictions or cessation of operations and the imposition of penalties and fines. See also "Risk Factors".

**Competitive Conditions**

The oil and natural gas industry is intensely competitive in all its phases. Yoho competes 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. Yoho's competitors include resource companies which have greater financial resources, staff and facilities than those of Yoho. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. Yoho believes that its competitive position is equivalent to that of other oil and gas issuers of similar size and at a similar stage of development.

## SIGNIFICANT ACQUISITIONS

The Corporation has not made any significant acquisitions during the year ended September 30, 2015 for which disclosure is required pursuant to Part 8 of National Instrument 51-102 – *Continuous Disclosure Obligations*.

## STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated November 18, 2015. The effective date of the Statement is September 30, 2015 and the preparation date of the Statement was November 18, 2015. The Report on Reserves Data by GLJ in Form 51-101F2 and the Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 are respectively attached as Appendices A and B to this Annual Information Form. See also "*Material Changes to Reserves Information*".

**Disclosure Of Reserves Data**

The reserves data set forth below (the "**Reserves Data**") is based upon the GLJ Report. The Reserves Data summarizes our oil, liquids and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs. The Reserves Data summarizes the crude oil, natural gas liquids and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using forecast prices and costs prior to the provision for interest, general and administrative expenses, the impact of hedging activities, certain well abandonment costs and all reclamation costs, which were not deducted by GLJ in estimating future net revenue. The GLJ Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which we believe is important to the readers of this information. The Corporation engaged GLJ to provide an evaluation of proved and proved plus probable reserves.

All of our reserves are in Canada and, specifically, in the provinces of Alberta, British Columbia and Saskatchewan as of September 30, 2015. On December 17, 2015, Yoho closed the Kaybob Duvernay Disposition. See "*Material Changes to Reserves Information*" and "*General Developments of our Business – Three Year History – Recent Developments*".

**Disclosure provided herein in respect of boe may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6 mcf: 1 bbl, utilizing a conversion ratio of 6 mcf: 1 bbl may be a misleading indication of value.**

**Disclosure provided herein in respect of Mcfe may be misleading, particularly if used in isolation. The Mcfe conversion ratio of one Bbl of oil to six thousand cubic feet of gas used throughout this document is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.**

**It should not be assumed that the estimates of future net revenues presented in the tables below 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 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.**

## RESERVES DATA (FORECAST PRICES AND COSTS)

### SUMMARY OF OIL AND GAS RESERVES
### AS OF SEPTEMBER 30, 2015
### FORECAST PRICES AND COSTS

| | RESERVES | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | LIGHT AND MEDIUM OIL | | HEAVY OIL | | CONVENTIONAL NATURAL GAS | | SHALE NATURAL GAS | |
| **RESERVES CATEGORY** | Gross (MBbl) | Net (MBbl) | Gross (MBbl) | Net (MBbl) | Gross (MMcf) | Net (MMcf) | Gross (MMcf) | Net (MMcf) |
| **PROVED** | | | | | | | | |
| Developed Producing | 134 | 120 | 73 | 72 | 8,142 | 7,933 | 8,082 | 7,392 |
| Developed Non-Producing | 9 | 10 | 24 | 22 | 886 | 831 | 3,913 | 3,593 |
| Undeveloped | 132 | 112 | - | - | 5,166 | 4,997 | 38,884 | 35,968 |
| **TOTAL PROVED** | 275 | 242 | 97 | 94 | 14,194 | 13,761 | 50,879 | 46,953 |
| **TOTAL PROBABLE** | 214 | 182 | 26 | 24 | 8,207 | 7,874 | 144,347 | 132,893 |
| **TOTAL PROVED PLUS PROBABLE** | 489 | 424 | 123 | 118 | 22,401 | 21,634 | 195,226 | 179,846 |

| | RESERVES | | | |
|---|---|---|---|---|
| | NATURAL GAS LIQUIDS | | TOTAL RESERVES | |
| **RESERVES CATEGORY** | Gross (MBbl) | Net (MBbl) | Gross (Mboe) | Net (Mboe) |
| **PROVED** | | | | |
| Developed Producing | 1,232 | 898 | 4,142 | 3,644 |
| Developed Non-Producing | 375 | 284 | 1,208 | 1,053 |
| Undeveloped | 3,931 | 3,138 | 11,405 | 10,077 |
| **TOTAL PROVED** | 5,537 | 4,320 | 16,755 | 14,774 |
| **TOTAL PROBABLE** | 16,099 | 12,481 | 41,764 | 36,149 |
| **TOTAL PROVED PLUS PROBABLE** | 21,636 | 16,801 | 58,519 | 50,923 |

### SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
### AS OF SEPTEMBER 30, 2015
### FORECAST PRICES AND COSTS

| | NET PRESENT VALUES OF FUTURE NET REVENUE *BEFORE INCOME TAXES DISCOUNTED AT* | | | | | Unit Value Before Income Tax Discounted at 10% per Year | |
|---|---|---|---|---|---|---|---|
| **RESERVES CATEGORY** | **0% (M$)** | **5% (M$)** | **10% (M$)** | **15% (M$)** | **20% (M$)** | **$/boe** | **$/Mcfe** |
| **PROVED** | | | | | | | |
| Developed Producing | 71,945 | 54,066 | 43,388 | 36,515 | 31,775 | 11.91 | 1.98 |
| Developed Non-Producing | 22,267 | 14,282 | 10,213 | 7,780 | 6,154 | 9.70 | 1.62 |
| Undeveloped | 170,545 | 83,716 | 41,162 | 17,600 | 3,376 | 4.08 | 0.68 |
| **TOTAL PROVED** | 264,757 | 152,064 | 94,763 | 61,896 | 41,305 | 6.41 | 1.07 |
| **TOTAL PROBABLE** | 969,853 | 444,329 | 234,867 | 134,430 | 80,222 | 6.50 | 1.08 |
| **TOTAL PROVED PLUS PROBABLE** | 1,234,610 | 596,392 | 329,630 | 196,326 | 121,527 | 6.47 | 1.08 |

**SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE**
**AS OF SEPTEMBER 30, 2015**
**FORECAST PRICES AND COSTS**

| | **NET PRESENT VALUES OF FUTURE NET REVENUE *AFTER INCOME TAXES DISCOUNTED AT*** | | | | |
|---|---|---|---|---|---|
| **RESERVES CATEGORY** | **0% (M$)** | **5% (M$)** | **10% (M$)** | **15% (M$)** | **20% (M$)** |
| **PROVED** | | | | | |
| Developed Producing | 71,945 | 54,066 | 43,388 | 36,515 | 31,775 |
| Developed Non-Producing | 21,748 | 14,146 | 10,175 | 7,769 | 6,150 |
| Undeveloped | 124,313 | 60,261 | 27,912 | 9,507 | (1,862) |
| **TOTAL PROVED** | 218,006 | 128,474 | 81,475 | 53,791 | 36,063 |
| **TOTAL PROBABLE** | 708,506 | 315,144 | 158,075 | 83,427 | 43,894 |
| **TOTAL PROVED PLUS PROBABLE** | 926,512 | 443,618 | 239,551 | 137,218 | 79,958 |

**TOTAL FUTURE NET REVENUE (UNDISCOUNTED)**
**AS OF SEPTEMBER 30, 2015**
**FORECAST PRICES AND COSTS**

| **RESERVES CATEGORY** | **REVENUE (M$)** | **ROYALTIES (M$)** | **OPERATING COSTS (M$)** | **CAPITAL DEVELOP-MENT COSTS (M$)** | **ABANDON-MENT & RECL. COSTS(1) (M$)** | **FUTURE NET REVENUE BEFORE INCOME TAXES (M$)** | **INCOME TAXES (M$)** | **FUTURE NET REVENUE AFTER INCOME TAXES (M$)** |
|---|---|---|---|---|---|---|---|---|
| Total Proved Reserves | 776,380 | 122,738 | 220,780 | 157,336 | 10,769 | 264,757 | 46,751 | 218,006 |
| Total Probable | 2,390,191 | 413,930 | 554,541 | 439,906 | 11,962 | 969,853 | 261,347 | 708,506 |
| Proved Plus Probable Reserves | 3,166,571 | 536,667 | 775,321 | 597,242 | 22,731 | 1,234,610 | 308,098 | 926,512 |

Note:

(1) Abandonment and reclamation costs have been estimated by GLJ in the GLJ Report and attributed to all properties that have been assigned reserves in the GLJ Report. For further information see "*Other Oil and Gas Information - Additional Information Concerning Abandonment and Reclamation Costs*".

**FUTURE NET REVENUE**
**BY PRODUCTION GROUP**
**AS OF SEPTEMBER 30, 2015**
**FORECAST PRICES AND COSTS**

| RESERVES CATEGORY | PRODUCT TYPE | FUTURE NET REVENUE BEFORE INCOME TAXES discounted at 10%/year (1) (M$) | $/boe | $/Mcfe |
|---|---|---|---|---|
| Proved Producing | Light and Medium Crude Oil (including solution gas and other by-products) | 1,270 | 8.82 | 1.47 |
| | Heavy Oil (including solution gas and other by-products) | 1,344 | 18.33 | 3.05 |
| | Natural Gas (including by-products but excluding solution gas from oil wells) | 8,039 | 5.74 | 0.96 |
| | Shale Natural Gas | 32,735 | 16.15 | 2.69 |
| | Total | 43,388 | 11.91 | 1.98 |
| Total Proved | Light and Medium Crude Oil (including solution gas and other by-products) | 2,711 | 9.98 | 1.66 |
| | Heavy Oil (including solution gas and other by-products) | 1,570 | 15.99 | 2.66 |
| | Natural Gas (including by-products but excluding solution gas from oil wells) | 8,743 | 3.63 | 0.60 |
| | Shale Natural Gas | 81,739 | 6.81 | 1.14 |
| | Total | 94,763 | 6.41 | 1.07 |
| Total Proved plus Probable | Light and Medium Crude Oil (including solution gas and other by-products) | 3,979 | 3.90 | 0.65 |
| | Heavy Oil (including solution gas and other by-products) | 1,994 | 16.14 | 2.69 |
| | Natural Gas (including by-products but excluding solution gas from oil wells) | 14,987 | 3.90 | 0.65 |
| | Shale Natural Gas | 308,670 | 6.63 | 1.11 |
| | Total | 329,630 | 6.47 | 1.08 |

Note:

(1) Yoho's revenue and costs not related to a specific production group have been allocated proportionately to production groups. Unit values are based on Yoho's net reserves.

(2) Abandonment and reclamation costs were deducted in estimating Yoho's future net revenue in this table. For a discussion on abandonment and reclamation costs see "*Statement of Reserves Data and Other Oil and Gas Information – Abandonment and Reclamation Costs*".

## RESERVES RECONCILIATION

### RECONCILIATION OF CORPORATION GROSS RESERVES AS OF SEPTEMBER 30, 2015 FORECAST PRICES AND COSTS

| | LIGHT AND MEDIUM OIL | | | HEAVY OIL | | |
|---|---|---|---|---|---|---|
| RESERVES CATEGORY | Gross Proved (MBbl) | Gross Probable (MBbl) | Gross Proved Plus Probable (MBbl) | Gross Proved (MBbl) | Gross Probable (MBbl) | Gross Proved Plus Probable (MBbl) |
| September 30, 2014 | 326 | 252 | 578 | 92 | 29 | 121 |
| Discoveries | - | - | - | - | - | - |
| Extensions & Improved Recovery | - | - | - | - | - | - |
| Technical Revisions | (25) | (39) | (64) | 20 | (3) | 17 |
| Acquisitions | - | - | - | - | - | - |
| Dispositions | - | - | - | - | - | - |
| Economic Factors | - | - | - | - | - | - |
| Production | (25) | - | (25) | (16) | - | (16) |
| September 30, 2015 | 275 | 214 | 489 | 97 | 26 | 123 |

| | CONVENTIONAL NATURAL GAS | | | SHALE GAS | | |
|---|---|---|---|---|---|---|
| RESERVES CATEGORY | Gross Proved (MMcf) | Gross Probable (MMcf) | Gross Proved Plus Probable (MMcf) | Gross Proved (MMcf) | Gross Probable (MMcf) | Gross Proved Plus Probable (MMcf) |
| September 30, 2014 | 16,948 | 9,968 | 26,916 | 27,355 | 64,678 | 92,033 |
| Discoveries | - | - | - | - | - | - |
| Extensions & Improved Recovery | - | - | - | 33,288 | 55,879 | 89,167 |
| Technical Revisions | (1,428) | (1,166) | (2,594) | 1,117 | 17,223 | 18,340 |
| Acquisitions | - | - | - | - | - | - |
| Dispositions | - | (595) | (595) | - | - | - |
| Economic Factors | - | - | - | (9,782) | 6,567 | (3,216) |
| Production | (1,326) | - | (1,326) | (1,100) | - | (1,100) |
| September 30, 2015 | 14,194 | 8,207 | 22,401 | 50,879 | 144,347 | 195,226 |

| | NATURAL GAS LIQUIDS | | | BOE | | |
|---|---|---|---|---|---|---|
| RESERVES CATEGORY | Gross Proved (MBbl) | Gross Probable (MBbl) | Gross Proved Plus Probable (MBbl) | Gross Proved (Mboe) | Gross Probable (Mboe) | Gross Proved Plus Probable (Mboe) |
| September 30, 2014 | 3,831 | 7,333 | 11,164 | 11,632 | 20,056 | 31,688 |
| Discoveries | - | - | - | - | - | - |
| Extensions & Improved Recovery | 3,369 | 5,725 | 9,094 | 8,917 | 15,038 | 23,955 |
| Technical Revisions | (117) | 2,110 | 1,993 | (174) | 4,745 | 4,571 |
| Acquisitions | - | - | - | - | - | - |
| Dispositions | - | (23) | (23) | - | (122) | (122) |
| Economic Factors | (1,375) | 953 | (422) | (3,005) | 2,047 | (957) |
| Production | (171) | - | (171) | (615) | - | (615) |
| September 30, 2015 | 5,537 | 16,099 | 21,636 | 16,755 | 41,764 | 58,519 |

## Definitions and Other Notes

In the tables set forth above in "Disclosure of Reserves Data" and elsewhere in this Annual Information Form, the following definitions and other notes are applicable:

"**Gross**" means:

(a) in relation to our interest in production and reserves, our interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Corporation;

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

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

"**Net**" means:

(a) in relation to our interest in production and reserves, our interest (operating and non-operating) share after deduction of royalty obligations, plus our royalty interest in production or reserves;

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

(c) in relation to our interest in a property, the total area in which we have an interest multiplied by our working interest.

Definitions used for reserve categories are as follows:

**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

(a) analysis of drilling, geological, geophysical and engineering data;

(b) the use of established technology; and

(c) specified economic conditions, which are generally accepted as being reasonable and shall be disclosed.

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

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

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

**Development and Production Status**

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

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

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

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

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

**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:

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

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the 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.

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

Numbers in the tables may not add due to rounding.

The estimates of future net revenue presented in the tables above do not represent fair market value.

**Pricing Assumptions**

The following data sets forth the benchmark reference prices, as at September 30, 2015, reflected in the Reserves Data. The forecast prices and cost assumptions were provided to us by GLJ, our independent qualified reserves evaluator.

**Forecast Prices and Costs**

These are prices and costs that are:

(a) generally acceptable as being a reasonable outlook of the future; and

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

The forecast cost and price assumptions include increases in actual wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil, heavy oil, natural gas and natural gas liquids benchmark reference pricing, as at September 30, 2015, inflation and exchange rates utilized in the GLJ Report were as follows:

**SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS**
**AS OF SEPTEMBER 30, 2015**
**FORECAST PRICES AND COSTS**

| | Crude Oil | | | Natural Gas Liquids | | |
|---|---|---|---|---|---|---|
| **Year** | **WTI Cushing Oklahoma ($US/Bbl)** | **Edmonton Par Price 40 API ($Cdn/Bbl)** | **Hardisty Heavy 12 API ($Cdn/Bbl)** | **Edmonton Propane ($/Cdn/Bbl)** | **Edmonton Butane ($/Cdn/Bbl)** | **Edmonton Pentanes Plus ($Cdn/Bbl)** |
| 2015 Q4 | 45.00 | 56.00 | 36.69 | 14.00 | 36.40 | 58.80 |
| 2016 | 50.00 | 61.33 | 42.30 | 15.33 | 39.87 | 65.63 |
| 2017 | 55.00 | 64.52 | 46.23 | 19.35 | 45.16 | 69.03 |
| 2018 | 60.00 | 68.75 | 50.22 | 24.06 | 51.56 | 73.56 |
| 2019 | 65.00 | 72.73 | 54.13 | 25.45 | 54.55 | 77.82 |
| 2020 | 70.00 | 76.47 | 57.96 | 26.76 | 57.35 | 81.82 |
| 2021 | 75.00 | 82.35 | 63.56 | 28.82 | 61.76 | 88.12 |
| 2022 | 80.00 | 88.24 | 69.32 | 30.88 | 66.18 | 94.41 |
| 2023 | 85.00 | 94.12 | 75.24 | 32.94 | 70.59 | 100.71 |
| 2024 | 89.63 | 98.41 | 78.71 | 34.44 | 73.81 | 105.30 |
| Thereafter escalate at 2% per year | | | | | | |

| | Natural Gas | | | |
|---|---|---|---|---|
| **Year** | **AECO –C Spot ($Cdn/MMBtu)** | **Westcoast Station 2 ($Cdn/MMBtu)** | **INFLATION RATES(1) %/Year** | **EXCHANGE RATE(2) ($US/$Cdn)** |
| 2015 Q4 | 2.97 | 2.17 | 2.0 | 0.75 |
| 2016 | 3.43 | 3.03 | 2.0 | 0.75 |
| 2017 | 3.62 | 3.42 | 2.0 | 0.775 |
| 2018 | 3.72 | 3.52 | 2.0 | 0.80 |
| 2019 | 3.81 | 3.61 | 2.0 | 0.825 |
| 2020 | 3.90 | 3.70 | 2.0 | 0.85 |
| 2021 | 4.10 | 3.90 | 2.0 | 0.85 |
| 2022 | 4.30 | 4.10 | 2.0 | 0.85 |
| 2023 | 4.50 | 4.30 | 2.0 | 0.85 |
| 2024 | 4.78 | 4.58 | 2.0 | 0.85 |
| Thereafter escalate at 2% per year | | | | |

Notes:

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

Weighted average historical wellhead prices realized by Yoho for the year ended September 30, 2015, were $2.56 per Mcf for natural gas, $52.73 per bbl for oil (light, medium and heavy) and $44.39 per bbl for natural gas liquids.

## MATERIAL CHANGES TO RESERVES INFORMATION

Subsequent to the year ended September 30, 2015, Yoho completed the Kaybob Duvernay Disposition which has had a material change on the reserves information of Yoho as at September 30, 2015 as further set forth above under "*Reserve Information and Other Oil and Gas Information*".

*Kaybob Duvernay Disposition*

On December 17, 2015, Yoho closed a transaction to sell approximately 75% of its net Duvernay acreage in the Kaybob area of Alberta for cash consideration of $50 million (prior to adjustments). The total proved reserves and total proved plus probable reserves for the assets disposed of pursuant to the Kaybob Duvernay Disposition by Yoho effective September 30, 2015 as determined by GLJ in the GLJ Report in accordance with NI 51-101 were 10,953 Mboe and 45,416 Mboe respectively (in each case based on Yoho's Gross reserves). Average production (net to Yoho) from the assets to disposed of pursuant to the Kaybob Duvernay Disposition were approximately 905 boe per day for fiscal 2015. See "*General Developments of Our Business – Three Year History – Recent Developments*".

Further information on the assets subject to the Kaybob Duvernay Disposition as at September 30, 2015, is set forth below.

**SUMMARY OF OIL AND GAS RESERVES ASSOCIATED WITH THE KAYBOB DUVERNAY ASSETS**
**AS OF SEPTEMBER 30, 2015**
**FORECAST PRICES AND COSTS**

| | **SHALE NATURAL GAS** | | **NATURAL GAS LIQUIDS** | | **TOTAL RESERVES** | |
|---|---|---|---|---|---|---|
| **RESERVES CATEGORY** | Gross (MMcf) | Net (MMcf) | Gross (MBbl) | Net (MBbl) | Gross (Mboe) | Net (Mboe) |
| **PROVED** | | | | | | |
| Developed Producing | 8,082 | 7,392 | 1,094 | 795 | 2,441 | 2,027 |
| Developed Non-Producing | - | - | - | - | - | - |
| Undeveloped | 32,361 | 30,023 | 3,118 | 2,463 | 8,512 | 7,466 |
| **TOTAL PROVED** | 40,443 | 37,415 | 4,212 | 3,258 | 10,953 | 9,493 |
| **TOTAL PROBABLE** | 124,188 | 114,552 | 13,766 | 10,610 | 34,463 | 29,703 |
| **TOTAL PROVED PLUS PROBABLE** | 164,631 | 151,967 | 17,978 | 13,868 | 45,416 | 39,196 |

**SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE ASSOCIATED**
**WITH THE KAYBOB DUVERNAY ASSETS**
**AS OF SEPTEMBER 30, 2015**
**FORECAST PRICES AND COSTS**

| | **NET PRESENT VALUES OF FUTURE NET REVENUE** ***BEFORE INCOME TAXES DISCOUNTED AT*** | | | | | **Unit Value Before Income Tax Discounted at 10% per Year** |
|---|---|---|---|---|---|---|
| **RESERVES CATEGORY** | **0% (M$)** | **5% (M$)** | **10% (M$)** | **15% (M$)** | **20% (M$)** | **$/boe** |
| **PROVED** | | | | | | |
| Developed Producing | 59,713 | 43,138 | 34,004 | 28,385 | 24,617 | 13.95 |
| Developed Non-Producing | - | - | - | - | - | - |
| Undeveloped | 124,476 | 57,440 | 24,852 | 6,910 | (3,871) | 2.92 |
| **TOTAL PROVED** | 184,188 | 100,579 | 58,856 | 35,295 | 20,746 | 5.38 |
| **TOTAL PROBABLE** | 797,880 | 356,828 | 182,591 | 99,931 | 55,930 | 5.30 |
| **TOTAL PROVED PLUS PROBABLE** | 982,068 | 457,405 | 241,447 | 135,226 | 76,676 | 5.32 |

## PRO-FORMA RESERVES INFORMATION

A summary of Yoho's reserves information at September 30, 2015, after giving effect to the Kaybob Duvernay Disposition, is set forth below.

**SUMMARY OF OIL AND GAS RESERVES
AS OF SEPTEMBER 30, 2015
FORECAST PRICES AND COSTS**

| | RESERVES | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | LIGHT AND MEDIUM OIL | | HEAVY OIL | | CONVENTIONAL NATURAL GAS | | SHALE NATURAL GAS | |
| RESERVES CATEGORY | Gross (MBbl) | Net (MBbl) | Gross (MBbl) | Net (MBbl) | Gross (MMcf) | Net (MMcf) | Gross (MMcf) | Net (MMcf) |
| **PROVED** | | | | | | | | |
| Developed Producing | 134 | 120 | 73 | 72 | 8,142 | 7,933 | - | - |
| Developed Non-Producing | 9 | 10 | 24 | 22 | 886 | 831 | 3,913 | 3,593 |
| Undeveloped | 132 | 112 | - | - | 5,166 | 4,997 | 6,523 | 5,945 |
| **TOTAL PROVED** | 275 | 242 | 97 | 94 | 14,194 | 13,761 | 10,436 | 9,538 |
| **TOTAL PROBABLE** | 214 | 182 | 26 | 24 | 8,207 | 7,874 | 20,159 | 18,341 |
| **TOTAL PROVED PLUS PROBABLE** | 489 | 424 | 123 | 118 | 22,401 | 21,635 | 30,595 | 27,879 |

| | RESERVES | | | |
|---|---|---|---|---|
| | NATURAL GAS LIQUIDS | | TOTAL RESERVES | |
| RESERVES CATEGORY | Gross (MBbl) | Net (MBbl) | Gross (Mboe) | Net (Mboe) |
| **PROVED** | | | | |
| Developed Producing | 138 | 103 | 1,701 | 1,617 |
| Developed Non-Producing | 375 | 284 | 1,208 | 1,053 |
| Undeveloped | 813 | 675 | 2,893 | 2,611 |
| **TOTAL PROVED** | 1,325 | 1,062 | 5,802 | 5,281 |
| **TOTAL PROBABLE** | 2,333 | 1,871 | 7,301 | 6,447 |
| **TOTAL PROVED PLUS PROBABLE** | 3,658 | 2,933 | 13,103 | 11,727 |

**SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF SEPTEMBER 30, 2015
FORECAST PRICES AND COSTS**

| | NET PRESENT VALUES OF FUTURE NET REVENUE *BEFORE INCOME TAXES DISCOUNTED AT* | | | | | Unit Value Before Income Tax Discounted at 10% per Year |
|---|---|---|---|---|---|---|
| RESERVES CATEGORY | 0% (M$) | 5% (M$) | 10% (M$) | 15% (M$) | 20% (M$) | $/boe |
| **PROVED** | | | | | | |
| Developed Producing | 12,232 | 10,928 | 9,384 | 8,130 | 7,158 | 5.29 |
| Developed Non-Producing | 22,267 | 14,282 | 10,213 | 7,780 | 6,154 | 8.45 |
| Undeveloped | 46,069 | 26,276 | 16,310 | 10,691 | 7,247 | 5.64 |
| **TOTAL PROVED** | 80,569 | 51,485 | 35,907 | 26,601 | 20,559 | 6.11 |
| **TOTAL PROBABLE** | 171,973 | 87,501 | 52,276 | 34,500 | 24,292 | 7.14 |
| **TOTAL PROVED PLUS PROBABLE** | 252,542 | 138,987 | 88,184 | 61,100 | 44,851 | 6.68 |

### Future Development Costs Pro Forma Reserves

The following table sets forth development costs deducted in the estimation of the future net revenue attributable to the pro forma reserve categories noted above.

| | Development Costs Forecast Prices and Costs | |
|---|---|---|
| | **Proved Reserves** | **Proved Plus Probable Reserves** |
| **Year** | **(M$)** | **(M$)** |
| Q4 2015 | 13,520 | 16,820 |
| 2016 | 208 | 18,404 |
| 2017 | 9,269 | 9,518 |
| 2018 | 249 | 4,515 |
| 2019 | 14,429 | 14,450 |
| 2020 | 88 | 14,717 |
| Remainder | 675 | 16,170 |
| Total Undiscounted (all years) | 38,438 | 94,594 |
| Total discounted at 10% | 31,991 | 73,734 |

## ADDITIONAL INFORMATION RELATING TO RESERVES DATA

### Proved and Probable Undeveloped Reserves

Undeveloped reserves are attributed by GLJ 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. Most of Yoho's proved undeveloped reserves relate to wells scheduled to be drilled in our 2016, 2017 and 2018 fiscal years.

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. The probable reserves are attributed to infill and step-out drilling locations, re-completions, and tie-ins that are anticipated to proceed within one to two years or to secondary zones that will be brought on production once the primary zone has been depleted and do not meet the confidence factor to be booked as proved reserves.

Yoho's proved and probable undeveloped reserves are attributed in accordance with NI 51-101. There are proved and probable undeveloped reserves assigned to development drilling at Kaybob, Alberta, with the remaining proved and probable undeveloped reserves assigned for drilling on minor conventional properties. Yoho will take a staged approach to development of the Duvernay resource play at Kaybob, Alberta. Some of these expenditures are planned to occur in 2016 and beyond. On December 17, 2015, Yoho completed the Kaybob Duvernay Disposition, resulting in the disposition of approximately 10,290 net acres with an average working interest of 39%. See "*General Business Developments of our Business – Three Year History – Recent Developments*" and "*Material Changes to Reserve Information*" above. A number of factors that could result in delayed or cancelled development of the Corporation's undeveloped reserves are as follows:

- changing economic conditions (due to pricing, royalty structure, operating and capital expenditure fluctuations);
- changing technical conditions or production anomalies (such as water breakthrough and accelerated depletion);
- multi-zone developments (such as production from a prospective formation completion may be delayed until the initial completion is no longer economic);
- a larger development program may need to be spread out over several years to optimize capital allocation and/or facility utilization; and
- surface access issues (landowners, weather conditions, regulatory approvals).

The following table sets forth, for each product type, the volumes of proved undeveloped reserves that were first attributed in each of the three most recent financial years.

**CORPORATION GROSS RESERVES FIRST ATTRIBUTED BY YEAR**

| Proved Undeveloped Reserves | LIGHT AND MEDIUM OIL (MBbl) | | HEAVY OIL (MBbl) | | NATURAL GAS (MMcf) | |
|---|---|---|---|---|---|---|
| | First Attributed | Total At Year End | First Attributed | Total At Year End | First Attributed | Total At Year End |
| 2013 | - | 125 | - | - | 3,442 | 15,874 |
| 2014 | - | 138 | - | - | - | 5,485 |
| 2015 | - | 132 | - | - | - | 5,166 |

| Proved Undeveloped Reserves | NATURAL GAS LIQUIDS (MBbl) | | SHALE GAS (MMcf) | | BOE (MBoe) | |
|---|---|---|---|---|---|---|
| | First Attributed | Total At Year End | First Attributed | Total At Year End | First Attributed | Total At Year End |
| 2013 | 425 | 2,240 | 2,214 | 14,076 | 1,368 | 7,357 |
| 2014 | 1,019 | 2,884 | 7,729 | 22,134 | 2,307 | 7,625 |
| 2015 | 2,528 | 3,931 | 25,436 | 38,884 | 6,768 | 11,405 |

The following table sets forth, for each product type, the volumes of probable undeveloped reserves that were first attributed in each of the three most recent financial years.

**CORPORATION GROSS RESERVES FIRST ATTRIBUTED BY YEAR**

| Probable Undeveloped Reserves | LIGHT AND MEDIUM OIL (MBbl) | | HEAVY OIL (MBbl) | | NATURAL GAS (MMcf) | |
|---|---|---|---|---|---|---|
| | First Attributed | Total At Year End | First Attributed | Total At Year End | First Attributed | Total At Year End |
| 2013 | 36 | 327 | - | - | 111,770 | 128,014 |
| 2014 | - | 126 | - | - | 1,125 | 9,612 |
| 2015 | - | 82 | - | - | - | 4,987 |

| Probable Undeveloped Reserves | NATURAL GAS LIQUIDS (MBbl) | | SHALE GAS (MMcf) | | BOE (MBoe) | |
|---|---|---|---|---|---|---|
| | First Attributed | Total At Year End | First Attributed | Total At Year End | First Attributed | Total At Year End |
| 2013 | 5,039 | 9,914 | 9,932 | 45,908 | 25,359 | 39,228 |
| 2014 | 2,319 | 7,066 | 16,249 | 59,503 | 5,215 | 18,636 |
| 2015 | 7,388 | 15,633 | 70,939 | 141,340 | 19,211 | 40,102 |

## Significant Factors or Uncertainties

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and natural gas prices and costs change. The reserve estimates disclosed herein as contained in the GLJ Report are based on production forecasts, prices and economic conditions at the time of preparation of such report. The reserves have been evaluated by GLJ.

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

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing economic or regulatory environment as well as fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond the control of Yoho may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and natural gas prices and reservoir performance. Such revisions can be either positive or negative. See "*Risk Factors*". Except as set forth herein, Yoho does not expect any abandonment or reclamation costs to materially affect any particular component of its reserves data.

**Future Development Costs**

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

| | Forecast Prices and Costs | |
|---|---|---|
| | **Proved Reserves** | **Proved Plus Probable Reserves** |
| **Year** | **(M$)** | **(M$)** |
| 2015 | 13,520 | 16,820 |
| 2016 | 54,267 | 72,464 |
| 2017 | 48,890 | 76,840 |
| 2018 | 15,769 | 93,590 |
| 2019 | 24,126 | 83,094 |
| 2020 | 88 | 73,233 |
| 2021 | 72 | 134,396 |
| 2022 | 55 | 45,715 |
| 2023 | 56 | 56 |
| 2024 | 57 | 57 |
| 2025 | 59 | 59 |
| 2026 | 60 | 60 |
| Remainder | 317 | 858 |
| Total Undiscounted (all years) | 157,336 | 597,243 |
| Total discounted 10% | 134,580 | 427,809 |

We expect to fund the development costs of our reserves through a combination of internally generated cash flow, equity and debt financing.

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

The interest or other costs of external funding are not included in the reserves and future net revenue estimates. The funding costs are minimal and will not significantly affect the economics of developing the properties.

Estimated future well abandonment costs related to our wells have been taken into account by GLJ in determining reserves that should be attributed to us. In determining the aggregate future net revenue, reasonable estimated future well abandonment and reclamation costs were deducted from the gross revenue amount.

The forecast price and cost assumptions assumed the continuance of current laws and regulations.

The extended character of all factual data supplied to GLJ was accepted by GLJ as represented. No field inspection was conducted.

## OTHER OIL AND GAS INFORMATION

**Principal Properties**

Yoho is engaged in the exploration for and development and production of crude oil and natural gas in Western Canada. All of our current operations to the end of this fiscal year are in the Provinces of Alberta, British Columbia and Saskatchewan.

The following is a description of our oil and natural gas properties as at September 30, 2015. Unless otherwise specified, well count information is as at September 30, 2015, which includes (for greater certainty) the wells prior to the Kaybob Duvernay Disposition.

**Northeastern British Columbia:** Yoho has continued to review its land base in British Columbia for both the Upper and Lower Montney formations. Other targets in northeastern British Columbia are the Lower Mannville, Dunlevy and Bluesky formations and the Triassic formations of the Halfway, Baldonnel and Charlie Lake.

- *Mike/Pickell:* Yoho's interests vary from 15% to 100% in 17 producing gas wells.
- *Buick Creek:* Yoho has varying interests in 13 producing gas wells with interest ranging from 4% to 78.5% in 12 wells and a 100% interest in one well.

**West Central Alberta:** Another core area for Yoho is in West Central Alberta. The main target in this area is the Devonian Duvernay formation at Kaybob. Other targets in the area include Spirit River and Gething Formations within the Cretaceous period and the Triassic aged wedge of sediments that subcrop throughout the area, including the Doig, Halfway, Boundary Lake, Charlie Lake and Baldonnel formations.

- *Kaybob:* Yoho has interests ranging from 1% to 100% in 32 producing gas wells. Included in these 32 producing wells, Yoho has working interests ranging from 14.25% to 75.0% working interest in 13 producing Duvernay horizontal gas wells.
- *Windfall:* Yoho has a 50% interest in five producing gas wells.
- *Boundary Lake:* Yoho has interests ranging from 26% to 60% in six producing gas wells.
- *Sinclair:* Yoho holds interests from 11% to 100% in three producing gas wells.
- *Spirit River:* Yoho has interests ranging from 2.5% to 50% in five producing gas wells.
- *Sweeney:* Yoho has a 40% working interest in six producing oil wells and two gas wells.
- *Worsley:* Yoho has a 50% interest in one producing gas well and interests ranging from 20% to 25% in two producing oil wells.

The following table indicates our average daily production before deduction of royalties and including royalty interests for the year ended September 30, 2015.

| | **Light and Medium Crude Oil & NGLs** | **Heavy Oil** | **Gas** |
|---|---|---|---|
| | (Bbl/d) | (Bbl/d) | (Mcf/d) |
| Boundary Lake | 5 | - | 308 |
| Buick Creek | 18 | - | 883 |
| Kaybob | 27 | - | 643 |
| Kaybob Duvernay | 401 | - | 3,015 |
| Mike | 2 | - | 737 |
| Sinclair | 2 | - | 254 |
| Spirit River | 7 | - | 57 |
| Sweeney | 58 | - | 96 |
| Windfall | 10 | - | 291 |
| Worsley | 7 | - | 28 |
| Other | 7 | 43 | 450 |
| Total | 544 | 43 | 6,762 |

## Oil and Gas Wells

The following table sets forth the number and status of wells in which we have a working interest as at September 30, 2015.

| | Natural Gas Wells | | | | Oil Wells | | | |
|---|---|---|---|---|---|---|---|---|
| | Producing | | Non-Producing | | Producing | | Non-Producing | |
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net |
| Alberta | 55 | 21.2 | 69 | 27.2 | 25 | 4.5 | 20 | 6.5 |
| British Columbia | 46 | 20.2 | 32 | 9.9 | 5 | 0.1 | 4 | 0.5 |
| Saskatchewan | - | - | - | - | 2 | 0.7 | 4 | 1.5 |
| Total | 101 | 41.3 | 101 | 37.1 | 32 | 5.2 | 28 | 8.5 |

## Properties with no Attributable Reserves

The following table sets out our undeveloped land holdings as September 30, 2015.

| | Undeveloped Acres | |
|---|---|---|
| | Gross | Net |
| Alberta | 43,808 | 19,890 |
| British Columbia | 60,545 | 49,342 |
| Total | 104,353 | 69,232 |

Yoho has no work commitments on these lands. We expect that rights to explore, develop and exploit 2,240 net acres of our undeveloped land holdings, absent further action, will expire by September 30, 2016. On December 17, 2015, Yoho completed the Kaybob Duvernay Disposition, resulting in the disposition of approximately 10,290 net acres with an average working interest of 39%. See "*General Business Developments of our Business – Three Year History – Recent Developments*".

## Significant Factors or Uncertainties Relevant to Properties With No Attributed Reserves

There are several economic factors and significant uncertainties that affect Yoho's anticipated development of its properties to which no reserves are attributed. Yoho will be required to make substantial capital expenditures in order to prove, exploit, develop and produce oil and natural gas from these properties in the future. If cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to the Yoho. Failure to obtain such financing on a timely basis could cause Yoho to forfeit its interest in certain properties, miss certain opportunities and reduce or terminate its operations on such properties. The inability of Yoho to access sufficient capital for its exploration and development purposes could have a material adverse effect on Yoho's ability to execute its business strategy to develop these prospects. See also "*Risk Factors*".

The primary economic factors that affect the development of these lands to which no reserves have been attributed are future commodity prices for crude oil and natural gas (and Yoho's outlook relating to such prices) and the future costs of drilling, completing, tying in and operating wells at the time that such activities are considered.

The primary uncertainties that affect the development of such lands are the future drilling and completion results achieved in the development activities, drilling and completion results achieved by others on lands in close proximity to these lands, and future changes to applicable regulatory or royalty regimes that affect timing or economics of proposed development activities. All of these uncertainties have the potential to delay the development of such lands. Conversely, uncertainty as to the timing and nature of the evolution or development of better exploration, drilling, completion and production technologies have the potential to accelerate development activities and enhance the economics relating to such lands.

Yoho does not expect any abandonment or reclamation costs to materially affect any potential activities on its properties with no attributed reserves.

## Forward Contracts

With the exception of the following financial derivative contracts entered into pursuant to the Corporation's risk management program, as of September 30, 2015, Yoho did not have any material commitments to buy or sell natural gas or crude oil production:

| Contract | Notional | Reference | Strike | Remaining Term | Fair Value |
|---|---|---|---|---|---|
| Natural Gas Swap | 1,000 GJ / day | AECO 5A in CAD per GJ | $2.65 | October 1, 2015 to October 31, 2015 | $2,285 |

**Additional Information Concerning Abandonment and Reclamation Costs**

Estimated future abandonment and reclamation costs related to well abandonment and reclamation of existing and future reserve wells have been taken into account by GLJ in determining reserves that should be attributed to a property and in determining the aggregated future net revenue therefrom. No allowance was made, however, the abandonment and reclamation of any pipelines or facilities.

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 (consisting of 92.1 net 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.

The additional liability associated with the wells not assigned reserves by GLJ in the GLJ Report, pipelines and facility reclamation costs, which were estimated to be $4 million as at September 30, 2015, were not deducted in estimating future net revenue in the GLJ Report.

**Tax Horizon**

Yoho was not required to pay any cash incomes taxes for the year ended September 30, 2015. The income taxes deducted in the calculation of future net revenue in the after tax table assumes a scenario whereby the Corporation produces out its existing reserves.

Based on current production and price assumptions and a continuing business model whereby the Corporation reinvests capital and incurs general and administrative and interest costs, the Corporation does not expect to pay cash income taxes until 2018 or later.

**Capital Expenditures**

The following table summarizes capital expenditures related to our activities for the year ended September 30, 2015.

| | |
|---|---|
| Property acquisition costs: | |
| Proved properties | - |
| Unproved properties | $1,390,178 |
| Exploration costs | $133,532 |
| Development costs | $33,016,111 |
| Total | $34,539,821 |

**Exploration and Development Activities**

The following table sets forth the gross and net exploratory and development wells in which we participated during the year ended September 30, 2015.

| | Exploratory Wells | | Development Wells | | Total Wells | |
|---|---|---|---|---|---|---|
| | **Gross** | **Net** | **Gross** | **Net** | **Gross** | **Net** |
| Oil | - | - | - | - | - | - |
| Natural Gas | - | - | 3 | 1.0 | 3 | 1.0 |
| Service | - | - | - | - | - | - |
| Dry | - | - | - | - | - | - |
| Total | - | - | 3 | 1.0 | 3 | 1.0 |

**Production Estimates**

The following table discloses the estimated first year average daily production of Yoho by product type associated with the first year of the Gross (working interest) proved reserves and probable reserves reported in the GLJ Report. The only individual property contributing production volumes in excess of 20% of the total set forth in the immediately following table is Kaybob Duvernay. On December 17, 2015, Yoho completed the Kaybob Duvernay Disposition. See "*General Developments of Our Business – Three Year History – Recent Developments*".

| | **LIGHT AND MEDIUM OIL (Bbl/d)** | **HEAVY OIL (Bbl/d)** | **CONVENTIONAL NATURAL GAS (Mcf/d)** | **SHALE NATURAL GAS (Mcf/d)** | **NATURAL GAS LIQUIDS (Bbl/d)** | **TOTAL OIL EQUIVALENT (boe/d)** |
|---|---|---|---|---|---|---|
| Kaybob Duvernay | - | - | - | 6,413 | 802 | 1,871 |
| Other Properties | 65 | 35 | 3,506 | 769 | 284 | 1,097 |
| **Total Proved Daily Production** | 65 | 35 | 3,506 | 7,182 | 1,086 | 2,967 |

| | **LIGHT AND MEDIUM OIL (Bbl/d)** | **HEAVY OIL (Bbl/d)** | **CONVENTIONAL NATURAL GAS (Mcf/d)** | **SHALE NATURAL GAS (Mcf/d)** | **NATURAL GAS LIQUIDS (Bbl/d)** | **TOTAL OIL EQUIVALENT (boe/d)** |
|---|---|---|---|---|---|---|
| Kaybob Duvernay | - | - | - | 512 | 73 | 159 |
| Other Properties | 1 | - | 23 | 5 | 2 | 8 |
| **Total Probable Daily Production** | 1 | - | 23 | 517 | 76 | 167 |

| | **LIGHT AND MEDIUM OIL (Bbl/d)** | **HEAVY OIL (Bbl/d)** | **CONVENTIONAL NATURAL GAS (Mcf/d)** | **SHALE NATURAL GAS (Mcf/d)** | **NATURAL GAS LIQUIDS (Bbl/d)** | **TOTAL OIL EQUIVALENT (boe/d)** |
|---|---|---|---|---|---|---|
| Kaybob Duvernay | - | - | - | 6,924 | 875 | 2,029 |
| Other Properties | 66 | 36 | 3,528 | 774 | 286 | 1,105 |
| **Total Proved and Probable Daily Production** | 66 | 36 | 3,528 | 7,699 | 1,161 | 3,134 |

**Production History and Prices Received - Fiscal 2015**

The following tables summarize certain information for our year ended September 30, 2015 in respect of production, product prices received, royalties paid, operating expenses, processing fees and resulting netback for the periods indicated below.

| **Production** | **Q1** | **Q2** | **Q3** | **Q4** |
|---|---|---|---|---|
| Natural Gas (Mcf/d) | 5,926 | 6,880 | 7,171 | 7,079 |
| Oil and NGL (Bbl/d) | 491 | 584 | 716 | 559 |
| BOE (boe/d) | 1,479 | 1,731 | 1,911 | 1,739 |

| **Q1** | **Natural Gas ($/Mcf)** | **Oil & NGLs ($/Bbl)** | **BOE ($/boe)** |
|---|---|---|---|
| Sales Price | 3.59 | 61.79 | 34.90 |
| Royalties | (0.25) | (4.72) | (2.57) |

| | | | |
|---|---|---|---|
| Operating Costs | (2.25) | (12.78) | (13.27) |
| **Operating Netback** | 1.09 | 44.29 | 19.06 |

| **Q2** | **Natural Gas ($/Mcf)** | **Oil & NGLs ($/Bbl)** | **BOE ($/boe)** |
|---|---|---|---|
| Sales Price | 2.43 | 38.79 | 22.75 |
| Royalties | (0.10) | (1.42) | (0.87) |
| Operating Costs | (2.48) | (10.88) | (13.53) |
| **Operating Netback** | (0.15) | 26.49 | 8.35 |

| **Q3** | **Natural Gas ($/Mcf)** | **Oil & NGLs ($/Bbl)** | **BOE ($/boe)** |
|---|---|---|---|
| Sales Price | 2.17 | 50.65 | 27.11 |
| Royalties | (0.09) | (1.27) | (0.80) |
| Operating Costs | (2.41) | (9.36) | (12.56) |
| **Operating Netback** | (0.33) | 40.02 | 13.75 |

| **Q4** | **Natural Gas ($/Mcf)** | **Oil & NGLs ($/Bbl)** | **BOE ($/boe)** |
|---|---|---|---|
| Sales Price | 2.22 | 40.46 | 22.03 |
| Royalties | (0.09) | (1.55) | (0.86) |
| Operating Costs | (1.96) | (14.13) | (12.52) |
| **Operating Netback** | 0.17 | 24.78 | 8.66 |

## 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, British Columbia and Saskatchewan all of which should be carefully considered by investors in the oil and gas industry. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in western Canada.

### 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 (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export license from the NEB. The NEB is currently undergoing a consultation process to update the regulations governing the issuance of export licenses. The updating process is necessary to meet the criteria set out in the federal *Jobs, Growth and Long-term Prosperity Act* (Canada) (the "**Prosperity Act**") which received Royal Assent on June 29, 2012. In this transitory period, the NEB has issued, and is currently following an "Interim Memorandum of Guidance concerning Oil and Gas Export Applications and Gas Import Applications" under Part VI of the *National Energy Board Act* (Canada).

### *Natural Gas*

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 NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 $m^3$/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 40 years) or for a larger quantity requires an exporter to obtain an export license from the NEB.

## The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply.

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

## Trans-Pacific Partnership

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

## Royalties and Incentives

### *General*

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

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are generally introduced when commodity prices are low to encourage exploration and development activity by improving earnings and cash flow within the industry.

The Federal Government has signaled it will, *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 United Nations 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***

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

Royalties are currently paid pursuant to "The New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) and the "Alberta Royalty Framework", which was implemented in 2010. Royalty rates for conventional oil are set by a single sliding rate formula, which is applied monthly and incorporates separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime is 40%. Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula with the maximum royalty payable under the royalty regime set at 36%.

Oil sands projects are also subject to Alberta's royalty regime. 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. In addition, concurrent with the implementation of The New Royalty Framework, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the new royalty regime.

On August 27, 2015, an advisory panel appointed by the Government of Alberta began a review of the royalty framework. The new royalty framework is scheduled to be announced by the end of January 2016. The Government of Alberta has committed that the current royalty framework will remain in place until at least the end of December 2016. Any changes to the royalty regime in Alberta may have a material effect on Yoho. See "*Risk Factors - Royalty Regimes*."

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

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. For example, the Innovative Energy Technologies Program (the "**IETP**") has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The IETP provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

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

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;

- Shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;

- Horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and

- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

### *British Columbia*

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, and make monthly royalty payments in respect of oil and natural gas produced. The amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of that oil. Generally, oil is classified as either light or heavy and the vintage of oil is classified as either "old oil" which is produced from a pool discovered before October 31, 1975, "new oil" produced from a pool discovered between October 31, 1975 and June 1, 1998, and "third-tier oil" produced from a pool discovered after June 1, 1998 or through an enhanced oil recovery ("**EOR**") scheme. The royalty calculation takes into account the production of oil on a well-by-well basis, the specified royalty rate for a given vintage of oil, the average unit selling price of the oil and any applicable royalty exemptions. Royalty rates are reduced on low-productivity wells, reflecting the higher unit costs of extraction, and are the lowest for third-tier oil, reflecting the higher unit costs of both exploration and extraction.

The royalty payable in respect of natural gas produced on Crown lands is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For non-conservation gas (not produced in association with oil), the royalty rate depends on the date of acquisition of the oil and natural gas tenure rights and the spud date of the well, and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty rate than non-conservation gas. Royalties on natural gas liquids are levied at a flat rate of 20% of sales volume.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For oil, the level of the freehold production tax is based on the volume of monthly production. It is either a flat rate, or, beyond a certain production level, is determined using a sliding scale formula based on the production level. For natural gas, the freehold production tax is either a flat rate, or, at certain production levels, is determined using a sliding scale formula based on the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas. The production tax rate for freehold natural gas liquids is a flat rate of 12.25%.

As of January 1, 2017, all liquid natural gas ("**LNG**") facilities will be subject to a 3.5% income tax. This income tax is scheduled to increase to 5% in 2037. During the period in which net operating losses and capital investment are deducted, a tax rate of 1.5% will apply to the taxpayer's net income. Once the net operating losses and capital investment have been depleted, the full rate of 3.5% is payable. To encourage investment the British Columbia government will offer a corporate income tax credit to any LNG taxpayer based on the amount of LNG acquired for an LNG facility.

British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity natural gas wells. These include both royalty credit and royalty reduction programs, including the following:

- *Deep Well Royalty Credit Program* providing a royalty credit for natural gas wells defined in terms of a dollar amount applied against royalties, is well specific and applies to drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 1,900 metres (or 2,300 metres if spud before September 1, 2009) and if certain other criteria are met, is intended to reflect the higher drilling and completion costs. Effective April 1, 2014, there are two tiers to the Deep Well Royalty Credit Program, "tier one" and "tier two". The pre-existing Deep Well Royalty Credit Program, as described above, will comprise tier two of the program. Tier one of the Deep Well Royalty Credit Program applies to shallower horizontal wells with a true vertical depth less than or equal to 1,900 metres if spud after March 31, 2014. Currently all wells that qualify for the tier one royalty credits are subject to a minimum royalty of 6% while wells that qualify for the tier two royalty credits are subject to a minimum royalty of 3%. These minimum royalty amounts apply when the net royalty payable would otherwise be zero for a production month;

- *Deep Re-Entry Royalty Credit Program* providing a royalty credit for deep re-entry wells with a true vertical depth to the top of pay if the re-entry well event is greater than 2,300 metres and a re-entry date after November 30, 2003; or if the well was spud on or after January 1, 2009, with a true vertical depth to the completion point of the re-entry well event being greater than 2,300 metres;

- *Deep Discovery Royalty Credit Program* providing the lesser of a 3 year royalty holiday or 283,000,000 $m^3$ of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation;

- *Coalbed Gas Royalty Reduction and Credit Program* providing a royalty reduction for coalbed gas wells with average daily production less than 17,000 $m^3$ as well as a royalty credit for coalbed gas wells equal to $50,000 for wells drilled on Crown land and a tax credit equal to $30,000 for wells drilled on freehold land;

- *Marginal Royalty Reduction Program* providing a monthly royalty reduction for low productivity natural gas wells with an average daily rate of production less than 23 $m^3$ for every metre of marginal well depth in the first 12 months of production. To be eligible, wells must have been spudded after May 31, 1998 and the first month of marketable gas production must have occurred between June 2003 and August 2008. Once a well passes the initial eligibility test, a reduction is realized in each month that average daily production is less than 25,000 $m^3$;

- *Ultra-Marginal Royalty Reduction Program* providing royalty reductions for low productivity, shallow natural gas wells. Vertical wells must be less than 2,500 metres and horizontal wells less than 2,300 metres to be eligible. Production in the first 12 months ending after January 2007 must be less than 17 $m^3$ per metre of depth for exploratory wildcat wells and less than 11 $m^3$ per metre of depth for development wells and exploratory outpost wells. The well must have been spudded or re-entered after December 31, 2005. A reduction is realized in each month that average daily production is less than 60,000 $m^3$. Horizontal wells that are spud on or after April 1, 2014 are not eligible for the Ultra-Marginal Royalty Reduction Program due to the potential for overlap with shallower horizontal wells eligible for a royalty credit under the Deep Well Royalty Credit Program; and

- *Net Profit Royalty Reduction Program* providing reduced initial royalty rates to facilitate the development and commercialization of technically complex resources such as coalbed gas, tight gas, shale gas and enhanced-recovery projects, with higher royalty rates applied once capital costs have been recovered.

Oil produced from an oil well that is located on either Crown or freehold land and completed in a new pool discovered subsequent to June 30, 1974 may also be exempt from the payment of a royalty for the first 36 months of production or 11,450 $m^3$ of production, whichever comes first.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program that provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to facilitate increased oil and gas exploration and production in under-developed areas and to extend the drilling season.

***Saskatchewan***

In Saskatchewan, taxes ("**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" ("**PTF**") applicable to that classification of oil. Currently the PTF 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 Saskatchewan government, 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 EOR projects during and subsequent to the payout of the EOR 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 EOR projects pre-payout and 20% of EOR operating income post-payout and a freehold production tax of 0% pre-payout and 8% post-payout on operating income from EOR 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 "**Associated Natural Gas Standards**"). The Associated Natural Gas 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 the western provinces, with the exception of Manitoba where private ownership accounts for approximately 80% of the crude oil and natural gas rights in the southwestern portion of the province. 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, British Columbia, Saskatchewan, and Manitoba 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. British Columbia expanded its policy of deep rights reversion for leases issued after March 29, 2007 to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of the primary term.

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 *Prosperity Act*, the Government of Canada amended or repealed several pieces of federal environmental legislation and in addition, created a new federal environment assessment regime that came in to force on July 6, 2012. The changes to the environmental legislation under the *Prosperity Act* are intended to provide for more efficient and timely environmental assessments of projects that previously had been subject to overlapping legislative jurisdiction.

***Alberta***

The Alberta Energy Regulator (the "**AER**") is the single regulator responsible for all energy development in Alberta. The AER ensures the safe, efficient, orderly, and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind 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 ("IRMS"). The IRMS method to natural resource management sets out to engage and consult with stakeholders and the public. While the AER is the primary regulator for energy development, several governmental departments and agencies may be involved in land use issues, including Alberta Environment and Parks, Alberta Energy, the AER, the Alberta Environmental Monitoring, Evaluation and Reporting Agency, the Policy Management Office, the Aboriginal Consultation Office, and the Land Use Secretariat.

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

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

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("**LARP**") which came into force on September 1, 2012. The LARP is the first of seven regional plans developed under the ALUF. LARP covers a region in the northeastern corner of Alberta that is approximately 93,212 square kilometres in size. The region includes a substantial portion of the Athabasca oil sands area, which contains approximately 82% of the province's oil sands resources and much of the Cold Lake oil sands area.

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

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

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

***British Columbia***

In British Columbia, the *Oil and Gas Activities Act* (the "**OGAA**") impacts conventional oil and gas producers, shale gas producers and other operators of oil and gas facilities in the province. Under the OGAA, the British Columbia Oil and Gas Commission (the "**Commission**") has broad powers, particularly with respect to compliance and enforcement and the setting of technical safety and operational standards for oil and gas activities. The *Environmental Protection and Management Regulation* establishes the government's environmental objectives for water, riparian habitats, wildlife and wildlife habitat, old-growth forests and cultural heritage resources. The OGAA requires the Commission to consider these environmental objectives in deciding whether or not to authorize an oil and gas activity. In addition, although not an exclusively environmental statute, the *Petroleum and Natural Gas Act*, in conjunction with the OGAA, requires proponents to obtain various approvals before undertaking exploration or production work, such as geophysical licenses, geophysical exploration project approvals, permits for the exclusive right to do geological work and geophysical exploration work, and well, test hole and water-source well authorizations. Such approvals are given subject to environmental considerations and licenses and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

***Saskatchewan***

In May 2011, Saskatchewan passed changes to *The Oil and Gas Conservation Act* ("**SKOGCA**"), 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* ("**OGCR**") and *The Petroleum Registry and Electronic Documents Regulations* ("**Registry Regulations**"). The aim of the amendments to the SKOGCA, 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 Registry Regulations and the OGCR, 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 AER implements the Licensee Liability Rating Program (the "**AB LLR Program**"). The AB LLR Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. The ABOGCA establishes an orphan fund (the "**Orphan Fund**") to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program if a licensee or working interest participant ("**WIP**") becomes defunct. The Orphan Fund is funded by licensees in the AB LLR Program through a levy administered by the AER. The AB LLR Program is designed to minimize the risk to the Orphan Fund posed by unfunded liability of licensees and prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The AB LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the AER with a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month and failure to post the required security deposit may result in the initiation of enforcement action by the AER.

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

The AER implemented the inactive well compliance program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under *Directive 013:*

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

***British Columbia***

In British Columbia, the Commission implements the Liability Management Rating ("**LMR**") Program, designed to manage public liability exposure related to oil and gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. Under the LMR Program, the Commission determines the required security deposits for permit holders under the OGAA. The LMR is the ratio of a permit holder's deemed assets to deemed liabilities. Permit holders whose deemed liabilities exceed deemed assets will be considered high risk and reviewed for a security deposit. Permit holders who fail to submit the required security deposit within the allotted timeframe may be in non-compliance with the OGAA.

***Saskatchewan***

In Saskatchewan, the Ministry of Economy implements the Licensee Liability Rating Program (the "**SK LLR Program**"). The SK LLR 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 (the "**Oil and Gas Orphan Fund**") established under the SKOGCA. The Oil and Gas Orphan Fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when a licensee or WIP is defunct or missing. The SK LLR 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* (the "**UNFCCC**") and a participant to the Copenhagen Accord (a non-binding agreement created by the UNFCCC which represents a broad political consensus and reinforces commitments to reducing greenhouse gas ("**GHG**") emissions). On January 29, 2010, Canada inscribed in the Copenhagen Accord its 2020 economy-wide target of a 17% reduction of GHG emissions from 2005 levels. This target is aligned with the United States target. In a report dated October 2013, the Government stated that this target represents a significant challenge in light of strong economic growth (Canada's economy is projected to be approximately 31% larger in 2020 compared to 2005 levels).

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets, for application to regulated sectors on a facility-specific 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 GHG emissions and is working on regulations for other sectors. Representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. In

June 2012, the second US-Canada Clean Energy Dialogue Action Plan was released. The plan renewed efforts to enhance bilateral collaboration on the development of clean energy technologies to reduce GHG emissions.

In December 2015, at the United Nations Paris Climate Conference, Canada became a signatory to an agreement which has set broad goals to, among other things, limit global climate change to not more than 2 degrees Celsius (or less), preparing, maintaining and publishing national greenhouse gas reduction targets and creating a "carbon-neutral" world by 2050.

***Alberta***

As part of its efforts to reduce GHG emissions, Alberta introduced legislation to address GHG emissions: the *Climate Change and Emissions Management Act* (the "**CCEMA**") enacted on December 4, 2003 and amended through the *Climate Change and Emissions Management Amendment Act*, which received royal assent on November 4, 2008. The accompanying regulations include the *Specified Gas Emitters Regulation* ("**SGER**"), which imposes GHG limits, and the *Specified Gas Reporting Regulation*, which imposes GHG emissions reporting requirements. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their GHG emissions. The SGER applies to facilities emitting more than 100,000 tonnes of GHGs in 2003 or any subsequent year ("**Regulated Emitters**"), and requires reductions in GHG emissions intensity (e.g. the quantity of GHG emissions per unit of production) from emissions intensity baselines established in accordance with the SGER.

On June 25, 2015, the Government of Alberta renewed the SGER for a period of two years with significant amendments while Alberta's newly formed Climate Advisory Panel conducted a comprehensive review of the province's climate change policy. In 2015, Regulated Emitters are required to reduce their emissions intensity by 2% from their baseline in the fourth year of commercial operation, 4% of their baseline in the fifth year, 6% of their baseline in the sixth year, 8% of their baseline in the seventh year, 10% of their baseline in the eighth year, and 12% of their baseline in the ninth or subsequent years. These reduction targets will increase, meaning that Regulated Emitters in their ninth or subsequent years of commercial operation must reduce their emissions intensity from their baseline by 15% in 2016 and 20% in 2017.

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

On November 22, 2015, as a result of the Climate Advisory Panel's Climate Leadership report, the Government of Alberta announced its Climate Leadership Plan which proposes to introduce a carbon tax on all emitters. An economy-wide levy $30 per tonne of GHG emissions will be phased in, starting in January 2017 at $20 per tonne, and increasing to $30 per tonne in January 2018. An oil sands specific approach was proposed to replace the $30 per tonne of GHG emissions to further reduce emissions and promote carbon competitiveness rather than rewarding past intensity levels. A 100 megatonne per year limit for GHG emissions was proposed for oil sands operations, which currently emit roughly 70 megatonnes per year. This cap exempts new upgrading and cogeneration facilities, which are allocated a separate 10 megatonne limit. The existing SGER will be replaced for large industrial facilities with a Carbon Competitiveness Regulation ("**CCR**"), in which sector specific output-based carbon allocations will be used to ensure competitiveness.

Alberta is also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed $1.24 billion over 15 years to fund two large-scale carbon capture and storage projects that will begin commercializing the *t*echnology 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.

***British Columbia***

In February 2008, British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The current tax level is $30 per tonne of GHG emissions. The final scheduled increase took effect on July 1, 2012. There is no plan for further rate increases or expansions at this time. In order to make the tax revenue-neutral, British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

In the 2012 Budget, British Columbia announced that the government would undertake a comprehensive review of the carbon tax and its impact on British Columbians. The review covered all aspects of the carbon tax, including revenue neutrality, and considered the impact on the competitiveness of British Columbia businesses such as those in the agriculture sector, and in particular, British Columbia's food producers. After the review, British Columbia confirmed that it will keep its revenue-neutral carbon tax; the current carbon tax rates and tax base will be maintained and revenues will continue to be returned through tax reductions.

On April 3, 2008, British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* (the "**Cap and Trade Act**"), which received royal assent on May 29, 2008 and partially came into force by regulation of the Lieutenant Governor in Council. It sets a province-wide target of a 33% reduction in the 2007 level of GHG emissions by 2020 and an 80% reduction by 2050. Unlike the emissions intensity approach taken by the federal government and the Government of Alberta, the Cap and Trade Act establishes an absolute cap on GHG emissions. The *Reporting Regulation*, implemented under the authority of the Cap and Trade Act, sets out the requirements for the reporting of the GHG emissions from facilities in British Columbia emitting 10,000 tonnes or more of carbon dioxide equivalent emissions per year beginning on January 1, 2010. Those reporting operations with emissions of 25,000 tonnes or greater are required to have emissions reports verified by a third party. Recent amendments to the Cap and Trade Act repealed past requirements on public-sector organizations, including Crown corporations, to be carbon neutral by 2010, and they are now only required to produce annual carbon reduction plans and reports. Additional regulations that will further enable British Columbia to implement a cap and trade system are currently under development.

***Saskatchewan***

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. The MRGGA received Royal Assent on May 20, 2010 and will come into force on proclamation. The MRGGA establishes a framework for achieving the provincial target of a 20% reduction in GHG emissions from 2006 levels by 2020. Although the MRGGA and related regulations have yet to be proclaimed in force, draft versions indicate that 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 MRGGA will be based on emissions intensity or an absolute cap on emissions.

## RISK FACTORS

**Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision. The risks set out below are not an exhaustive list and should not be taken as a complete summary or description of all the risks associated with the Corporation's business and the oil and natural gas business generally.**

### Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, the Corporation's existing reserves, and the production from them, will decline over time as the Corporation produces from such reserves. A future increase in the Corporation's reserves will depend on both the ability of the Corporation to explore and develop its existing properties and its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Corporation will be able continue to find satisfactory properties to acquire or participate in. Moreover, management of the Corporation may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participations uneconomic. There is also no assurance that the Corporation will discover or acquire further commercial quantities of oil and natural gas.

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

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents, and shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment and personal injury. Particularly, the Corporation may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation.

Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

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

**Global Financial Markets**

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels, have caused significant volatility in commodity prices. These events and conditions have caused a decrease in confidence in the broader United States and global credit and financial markets and have created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and are likely to continue to impact the performance of the global economy going forward. Worldwide crude oil commodity prices are expected to remain volatile in the near future as a result of global excess supply, recent actions taken by the Organization of the Petroleum Exporting Countries ("**OPEC**"), and ongoing global credit and liquidity concerns. This volatility may affect the Corporation's ability to obtain equity or debt financing on acceptable terms.

**Prices, Markets and Marketing**

Numerous factors beyond the Corporation's control do, and will continue to, affect the marketability and price of oil and natural gas acquired or discovered by the Corporation. The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets or contract for the delivery of crude oil by rail. Deliverability uncertainties related to the distance the Corporation's reserves are from pipelines, railway lines, processing and storage facilities, operational problems affecting pipelines, railway lines and facilities as well as government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect the Corporation. Recently, certain of the Corporation's production has been shut-in as a result of restrictions and curtailments on TransCanada Pipelines' transportation network.

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

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

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions, sanctions imposed on certain oil producing nations by other countries and ongoing credit and liquidity concerns. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

**Market Price of Common Shares**

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

**Failure to Realize Anticipated Benefits of Acquisitions and Dispositions**

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

**Operational Dependence**

Other companies operate some of the assets in which the Corporation has an interest. The Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others depends upon a number of factors that may be outside of the Corporation's control, including, but not limited to, the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

**Project Risks**

The Corporation manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. The Corporation's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Corporation's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling and hydraulic fracturing, or the Corporation's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

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

**Gathering and Processing Facilities, Pipeline Systems and Rail**

The Corporation delivers its products through gathering and processing facilities and pipeline systems some of which it does not own and, may in the future transport by rail. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines, and in particular the processing facilities, could result in the Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation's production. Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. Furthermore, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically and it is projected to continue in this upward trend. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Corporation's business and, in turn, the Corporation's financial condition, results of operations and cash flows.

Following major accidents in Lac-Megantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the 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.

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

**Competition**

The petroleum industry is competitive in all of its phases. The Corporation competes with numerous other entities in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Corporation's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. The Corporation's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price, methods, and reliability of delivery and storage.

**Cost of New Technologies**

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

**Alternatives to and Changing Demand for Petroleum Products**

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

**Regulatory**

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

**Royalty Regimes**

There can be no assurance that the federal government and the provincial governments of the western provinces will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of the Corporation's projects. Alberta is currently reviewing its royalty framework and is scheduled to announce the new royalty regime in January 2016 and such regime changes are expected to come into effect in 2017. An increase in royalties would reduce the Corporation's earnings and could make future capital investments, or the Corporation's operations, less economic.

**Hydraulic Fracturing**

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

Due to recent seismic activity reported in the Fox Creek area of Alberta, the Alberta Energy Regulator has announced new seismic monitoring and reporting requirements for hydraulic fracturing operators in the Duvernay Zone in the Fox Creek area. These requirements include, among others, an assessment of the potential for seismicity prior to operations, the implementation of a response plan to address potential events, and the suspension of operations if a seismic event above a particular threshold occurs. The Alberta Energy Regulator continues to monitor seismic activity around the province and may extend these requirements to other areas of the province if necessary.

**Environmental**

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such 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 environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental legislation, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

**Liability Management**

Alberta, Saskatchewan and British Columbia 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 the Corporation's deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted. This is of particular concern to junior oil and gas companies as they may be disproportionately affected by price instability. See: "*Industry Conditions*".

**Climate Change**

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases which may require the Corporation to comply with greenhouse gas ("**GHG**") emissions legislation 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* (the "**UNFCCC**") and a participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction in GHG emissions from 2005 levels by 2020. These GHG emission reduction targets are not binding, however. Some of the Corporation's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. The direct or indirect costs of compliance with these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition. See also "*Industry Conditions – Climate Change Regulation*".

**Variations in Foreign Exchange Rates and Interest Rates**

World oil and natural gas prices are quoted in United States dollars. The Canadian/United States 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 relative to the United States dollar will negatively affect the Corporation's production revenues. Accordingly, exchange rates between Canada and the United States could affect the future value of the Corporation's reserves as determined by independent evaluators.

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

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

**Substantial Capital Requirements**

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

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

Further, if the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

**Additional Funding Requirements**

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

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

**Credit Facility Arrangements**

The Corporation currently has a credit facility and the amount authorized thereunder is dependent on the borrowing base determined by its lenders. The Corporation is required to comply with covenants under its credit facility which may, in certain cases, include certain financial ratio tests, which from time to time either affect the availability, or price, of additional funding and in the event that the Corporation does not comply with these covenants, the Corporation's access to capital could be restricted or repayment could be required. Events beyond the Corporation's control may contribute to the failure of the Corporation to comply with such covenants. A failure to comply with covenants could result in default under the Corporation's credit facility, which could result in the Corporation being required to repay amounts owing thereunder. Even if the Corporation is able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to the Corporation. If the Corporation is unable to repay amounts owing under credit facilities, the lenders under the credit facility could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. The acceleration of the

Corporation's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Corporation's credit facility may impose operating and financial restrictions on the Corporation that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to the Corporation's securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others. In addition to the Corporation's credit facilities, the Corporation also has Debentures outstanding, and any default under the terms of the Debentures may result in a cross-default under the terms of the Corporation's credit facility.

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

**Issuance of Debt**

From time to time, the Corporation may enter into transactions to acquire assets or shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase the Corporation's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Corporation may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time could impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

**Hedging**

From time to time, the Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that the Corporation engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Corporation's hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which:

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

Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars or other currencies in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to other currencies. However, if the Canadian dollar declines in value compared to such fixed currencies, the Corporation will not benefit from the fluctuating exchange rate.

**Availability of Drilling Equipment and Access**

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Corporation and may delay exploration and development activities.

**Diluent Supply**

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 the Corporation's overall operating cost, decreasing its net revenues and negatively impacting the overall profitability of its heavy oil and bitumen projects.

**Title to Assets**

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise. The actual interest of the Corporation in properties may accordingly vary from the Corporation's records. If a title defect does exist, it is possible that the Corporation may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes, which affect the Corporation's title to the oil and natural gas properties the Corporation controls that could impair the Corporation's activities on them and result in a reduction of the revenue received by the Corporation.

**Reserve Estimates**

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this document are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves and the future net cash flows from such estimated reserves are based upon a number of variable factors and assumptions, such as:

- historical production from the properties;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures;
- marketability of oil and natural gas;
- royalty rates; and
- the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates and such variations could be material.

The estimation of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves. Such variations could be material.

In accordance with applicable securities laws, the Corporation's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from the Corporation's oil and natural gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom and contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and, except as may be specifically stated, has not been updated and therefore does not reflect changes in the Corporation's reserves since that date.

**Insurance**

The Corporation's involvement in the exploration for and development of oil and natural gas properties may result in the Corporation becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Corporation maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, certain risks are not, in all circumstances, insurable or, in certain circumstances, the Corporation may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

**Geopolitical Risks**

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

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

**Dilution**

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

**Management of Growth**

The Corporation may be subject to growth related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Corporation to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of the Corporation to deal with this growth may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

**Expiration of Licences and Leases**

Certain of the Corporation's properties are held in the form of licences and leases and working interests in licences and leases. If the Corporation or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Corporation's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

**Dividends**

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

**Litigation**

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

**Intellectual Property Litigation**

Due to the rapid development of oil and gas technology, in the normal course of the Corporation's operations, the Corporation may become involved in, named as a party to, or be the subject of, various legal proceedings in which it is alleged that the Corporation has infringed the intellectual property rights of others or commenced lawsuits against others who the Corporation believes are infringing upon its intellectual property rights. The Corporation's involvement in intellectual property litigation could result in significant expense, adversely affecting the development of its assets or intellectual property or diverting the efforts of its technical and management personnel, whether or not such litigation is resolved in the Corporation's favour. In the event of an adverse outcome as a defendant in any such litigation, the Corporation may, among other things, be required to: (a) pay substantial damages; cease the development, use, sale or importation of processes 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. However, the Corporation may not be successful in such development or acquisition or such licences may not 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 the Corporation's business and financial results.

**Aboriginal Claims**

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

**Breach of Confidentiality**

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

**Income Taxes**

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

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

**Seasonality**

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. In addition, 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 decreases in the demand for the goods and services of the Corporation.

**Third Party Credit Risk**

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may affect a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

**Conflicts of Interest**

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

**Reliance on Key Personnel**

The Corporation's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have any key person insurance in effect for the Corporation. The contributions of the existing management team to the immediate and near term operations of the Corporation are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

**Expansion into New Activities**

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

**Forward Looking Information May Prove Inaccurate**

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

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

## DIRECTORS AND OFFICERS

The name, jurisdiction of residence, principal occupation for the prior five years of each of the directors and officers of Yoho are as follows:

| Name and Jurisdiction of Residence | Offices Held and Time as Director | Principal Occupation During the Last Five Years |
|---|---|---|
| Terry Svarich [1][3]<br>Alberta, Canada | Chairman of the Board since February 17, 2005 | Mr. Svarich is currently the President of DevSun Ltd., a private investment company. |
| Bruce Allford [2]<br>Alberta, Canada | Director since December 20, 2004 | Mr. Allford is a partner with the Calgary law firm, Burnet, Duckworth & Palmer LLP. |
| Brian McLachlan<br>Alberta, Canada | President, Chief Executive Officer and a Director since January 5, 2005 | Mr. McLachlan has been the President and Chief Executive Officer of Yoho since January of 2005. |
| Peter Kurceba [2][3][4]<br>Alberta, Canada | Director since February 9, 2006 | Independent businessman. Prior thereto, oil and gas industry advisor at J.F. Mackie & Company Ltd., an independent equity investment firm from October 2005 until May 2010. |
| Kevin Olson [1][2]<br>Alberta, Canada | Director since December 20, 2004 | Mr. Olson is the President of Kyklopes Capital Mgmt. Ltd., a registered fund manager. He has managed various energy funds since 2001 and is also currently a director of several energy corporations. |
| Gary Perron [1]<br>Alberta, Canada | Director since December 20, 2004 | Mr. Perron is a partner at Perron & Partners Wealth Management since November 1, 2013. Prior thereto, he was a Managing Director and Senior Vice President of BMO Nesbitt Burns Inc. |
| John A. Brussa<br>Alberta, Canada | Director since March 11, 2008 | Mr. Brussa is a partner of Calgary law firm, Burnet, Duckworth & Palmer LLP, specialising in taxation. Mr. Brussa is also a director of several energy and energy-related corporations. |
| Clark Drader<br>Alberta, Canada | Vice President, Land since May 1, 2005 | Mr. Drader has been the Vice President, Land of Yoho since May 1, 2005. |

| Name and Jurisdiction of Residence | Offices Held and Time as Director | Principal Occupation During the Last Five Years |
|---|---|---|
| Barry Stobo<br>Alberta, Canada | Vice President, Engineering and Chief Operating Officer since February 1, 2005 | Mr. Stobo has been the Vice President, Engineering and Chief Operating Officer of Yoho since February of 2005. |
| Wendy Woolsey<br>Alberta, Canada | Vice President, Finance and Chief Financial Officer since March 1, 2005 | Ms. Woolsey has been the Vice President, Finance and Chief Financial Officer of Yoho since March of 2005. |
| Gregory Niebergall<br>Alberta, Canada | Vice President, Exploration since November 4, 2013 | Mr. Niebergall has been the Vice President, Exploration of Yoho since November 4, 2013. Prior thereto, he has been employed by Yoho since July of 2008, most recently as Exploration Manager. |

Notes:

(1) Member of our Audit Committee.
(2) Member of our Compensation Committee.
(3) Member of our Reserves Committee.
(4) Prior to February 9, 2006, Mr. Kurceba served as a Special Advisor to the Board of Directors.

All directors of the Corporation are elected by the shareholders of the Corporation at each annual general meeting of the Shareholders to serve a term until the subsequent annual general meeting of the shareholders. As at January 13, 2016 the directors and executive officers of Yoho, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 12,193,211 Common Shares, or approximately 19.9% of the issued and outstanding Common Shares and $1,575,000 principal amount of Debentures, or approximately 13.3%, of the aggregate principal amount of the outstanding Debentures.

**Cease Trade Orders, Bankruptcies, Penalties or Sanctions**

Other than as set forth below, no director, officer or shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, within 10 years before the date of this Annual Information Form, has been, a director or executive officer of any company that, while that person was acting in that capacity:

(a) was the subject of a cease trade or similar order, or an order that denied the relevant company access to any exemption under securities legislation, for a period of more than 30 consecutive days;

(b) was subject to an event that resulted, after the director or executive officer ceased to be a director or executive officer, in the company being the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation, for a period of more than 30 consecutive days; or

(c) within a year of that person ceasing to act in such 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.

No director, officer or promoter of Yoho, or a shareholder holding sufficient securities of the Corporation to affect materially the control of the Corporation, or a personal holding company of any such persons, has, within the last 10 years, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangements or compromises with creditors, or had a receiver, receiver manager or trustee appointed to hold his or her assets.

No director, officer, Insider or Promoter of the Corporation, or any shareholder holding sufficient securities of the Corporation to affect materially the control of the Corporation, has been subject to: (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority, or (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in deciding whether to make an investment decision.

John Brussa resigned as a director of Calmena Energy Services Inc. ("**Calmena**") on June 30, 2014. On January 19, 2015, a senior lender of Calmena (the "**Senior Lender**") made an application to the Court of Queen's Bench of Alberta (the "**Court**") to appoint an interim receiver under the *Bankruptcy and Insolvency Act* (Canada) and trading in the common shares of Calmena was suspended by the Toronto Stock Exchange. On January 20, 2015, the Senior Lender was granted a receivership order by the Court. Mr. Brussa was also a director of Enseco Energy Services Corp. ("**Enseco**"), a public oilfield service company, which was placed in receivership on October 14, 2015 and, in connection therewith, a receiver was appointed under the *Bankruptcy and Insolvency Act* (Canada). Mr. Brussa resigned as a director of Enseco on October 14, 2015. On December 21, 2015 Enseco was assigned into bankruptcy by the receiver.

### Conflicts of Interest

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

### Personnel

As at September 30, 2015, the Corporation employed nine full-time employees and one part-time employee. Yoho intends to add additional professional and administrative staff as the need arises.

## YOHO SHARE CAPITAL

As of the date hereof, the authorized share capital of the Corporation consists of an unlimited number of Common Shares of which there are 61,154,831 Common Shares are issued and outstanding.

### Common Shares

The holders of Common Shares are entitled to dividends as and when declared by the Board of Directors of the Corporation, to one vote per share at meetings of shareholders of the Corporation and, upon liquidation, to receive such assets of the Corporation as are distributable to the holders of the Common Shares.

## DIVIDEND POLICY

Yoho has not paid any dividends. The Board of Directors of Yoho will determine the actual timing, payment and amount of dividends, if any, that may be paid by us from time to time based upon, among other things, the cash flow, results of operations and financial conditions of Yoho, the need for funds to finance ongoing operations and other business considerations as our Board of Directors considers relevant.

## MARKET FOR SECURITIES

The Common Shares are listed for trading on the TSXV under the symbol "YO". The following table sets forth the high and low closing trading prices and the aggregate volume of trading of the Common Shares (as reported by the TSXV) for the periods indicated.

| | Price Range High ($) | Price Range Low ($) | Volume Traded |
|---|---|---|---|
| 2015 | | | |
| January | 1.43 | 1.00 | 377,620 |
| February | 1.34 | 1.04 | 376,867 |
| March | 1.10 | 0.87 | 303,152 |
| April | 0.97 | 0.60 | 556,701 |
| May | 0.80 | 0.60 | 189,322 |
| June | 0.70 | 0.41 | 1,175,588 |
| July | 0.47 | 0.295 | 1,150,961 |
| August | 0.42 | 0.26 | 5,095,279 |
| September | 0.37 | 0.31 | 137,493 |
| October | 0.46 | 0.27 | 1,311,193 |
| November | 0.30 | 0.21 | 1,287,030 |
| December | 0.27 | 0.17 | 2,365,175 |
| 2016 | | | |
| January 1 – 13 | 0.275 | 0.19 | 252,475 |

## ESCROWED SECURITIES

There are no securities of the Corporation currently held in escrow.

## LEGAL PROCEEDINGS AND REGULATORY ACTIONS

To the knowledge of the Corporation, there are no outstanding legal proceedings material to the Corporation to which the Corporation is or was a party to, or in respect of which any of its properties are or were subject of during the year ended September 30, 2015, nor are there any such proceedings known to be contemplated.

During the year ended September 30, 2015, there were (i) no penalties or sanctions imposed against the Corporation or by a court relating to securities legislation or by a securities regulatory authority; (ii) no other penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision; and (iii) no settlement agreements the Corporation entered into with a court relating to a securities legislation or with a securities regulatory authority.

## INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

A company controlled by Mr. McLachlan, 358949 Alberta Ltd., has a one percent overriding royalty on certain lands held by the Corporation. This arrangement is the result of consulting work that 358949 Alberta Ltd. performed on these properties previous to Yoho acquiring these lands in February 2005. The lands to which the overriding royalty is applicable are fixed by defined prospect boundaries.

Other than set out above, there were other no material interests, direct or indirect, of directors and senior officers of the Corporation, nominees for director, any shareholder who beneficially owns more than 10% of the Common Shares or any known associate or affiliate of such persons in any transaction since the beginning of the Corporation's last completed financial year or in any proposed transaction which has materially affected or would materially affect the Corporation.

## AUDITORS, TRANSFER AGENT AND REGISTRAR

Our independent registered Chartered Accountants are KPMG LLP, Chartered Accountants, Calgary, Alberta.

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

## INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by us during, or related to, our most recently completed financial year other than GLJ, our independent engineering evaluator. None of the principals of GLJ have 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 GLJ Report, at any time thereafter or that are to be received by them. KPMG LLP are the auditors of the Corporation and have confirmed that they are independent of the Corporation within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of Yoho or of any associate or affiliate of Yoho, except for Bruce Allford and John Brussa, directors of Yoho, who are partners at Burnet, Duckworth & Palmer LLP, which law firm renders legal services to us.

## MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business or as otherwise disclosed herein or below, there have been no material contracts entered into by the Corporation within the most recently completed financial year or before the most recently completed financial year that are still in effect.

- On June 16, 2015, the Corporation entered into a debenture indenture with Valiant Trust Company governing the terms of the Corporation's outstanding Debentures. See "*General Developments of Our Business – Three Year History – Year Ended September 30, 2015*".

- On December 7, 2015, the Corporation entered into an agreement of purchase and sale with the purchaser party thereto with respect to the Kaybob Duvernay Disposition. See "*General Developments of Our Business – Three Year History – Recent Developments*".

Each of the foregoing agreements has been filed and is available for viewing on the Corporation's SEDAR profile at www.sedar.com.

## ADDITIONAL INFORMATION

Additional information relating to the Corporation can be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans is contained in the Corporation's information circular for the Corporation's most recent annual meeting of shareholders that involved the election of directors. Additional financial information is contained in the Corporation's consolidated financial statements and the related management's discussion and analysis for its most recently completed financial year.

Additional copies of this Annual Information Form and the materials listed in the preceding paragraph, any interim financial statements which have been issued by the Corporation are available on the foregoing basis and upon request by contacting the Corporation at:

Yoho Resources Inc.
500, 521 – 3rd Avenue SW
Calgary, Alberta T2P 3T3
Phone: (403) 537-1771
Fax: (403) 537-1775
www.yohoresources.ca

## APPENDIX A

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

To the Board of Directors of Yoho Resources Inc. (the "**Company**"):

1. We have evaluated the Company's reserves data as at September 30, 2015. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at September 30, 2015, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

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 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 the Company and evaluated for the year ended September 30, 2015, and identifies the respective portions thereof that we have evaluated and reported on to the Company's Board of Directors:

| Independent Qualified Reserves Evaluator | Effective Date of Evaluation Report | Location of Reserves (County or Foreign Geographic Area) | Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) -$M | | | |
|---|---|---|---|---|---|---|
| | | | Audited | Evaluated | Reviewed | Total |
| GLJ Petroleum Consultants | September 30, 2015 | Canada | - | 329,630 | - | 329,630 |

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after their respective preparation dates.

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

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, November 18, 2015.

(signed) "*Chad P. Lemke*"
Chad P. Lemke, P. Eng

## APPENDIX B

### FORM 51-101F3 REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Yoho Resources Inc. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

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

The Reserves Committee of the Board of Directors of the Company has:

(a) reviewed the Company'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 Reserves Committee of the Board of Directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved:

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

(e) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

(f) 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) "*Brian A. McLachlan*"
Brian A. McLachlan
President and Chief Executive Officer

(signed) "*Barry J. Stobo"*
Barry J. Stobo
Vice President, Engineering and Chief Operating Officer

(signed) "*Terry Svarich"*
Terry Svarich
Director

(signed) "*Peter Kurceba*"
Peter Kurceba
Director

January 13, 2016