



YOHO RESOURCES INC.

**ANNUAL INFORMATION FORM
FOR THE FISCAL YEAR ENDED SEPTEMBER 30, 2010**

DECEMBER 15, 2010

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ABBREVIATIONS AND CONVERSIONS

Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
MBbls	thousand barrels
MMBbls	million barrels
Mstb	1,000 stock tank barrels
Bbls/d	barrels per day
BOPD	barrels of oil per day
NGLs	natural gas liquids
STB	standard tank barrels

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
MMbtu	million British Thermal Units
Bcf	billion cubic feet
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
GCA	gas cost allowance
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
\$000s	thousands of dollars
\$M	thousands of dollars
\$MM	millions of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

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.

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
Bbls	cubic meters	0.159
cubic meters	Bbls 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 effect 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);

"**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;

"**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;

"**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 dated December 8, 2010 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, 2010;

"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 Arrangement on December 23, 2004 and subsequently cancelled on February 28, 2007;

"**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, 2010.

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 Arrangement pursuant to an arrangement agreement dated as of November 18, 2004 among the Corporation, VIQ Solutions Inc. ("**VIQ Solutions**") and Yoho Resources Investment Partnership. Pursuant to the 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 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, 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 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, 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 Common Shares on the basis of one (1) 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.

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

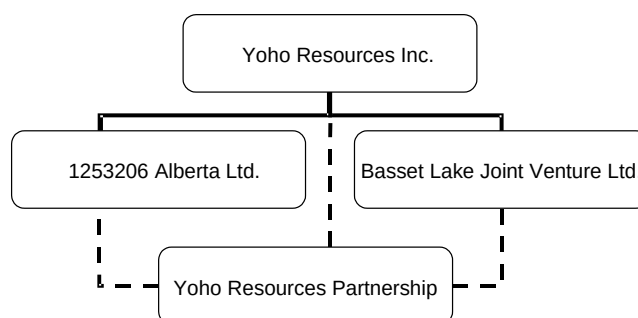
Yoho's head office is located at 750, 736 – 6th Avenue SW, Calgary, Alberta T2P 3T7 and the registered office is located at 1400, 350 – 7th Avenue SW, Calgary, Alberta T2P 4N9.

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 Arrangement in December 2004, the Corporation carried out a technology related business, specifically a voice capture, digitization and compression business.

Upon completion of the 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 having approximately 868 Mboe of proved plus probable reserves, 9,297 net acres of undeveloped land and production of approximately 736 boe/d. 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 pursue internal generation of exploration plays on natural gas and light oil projects, with an emphasis on medium risk, medium depth targets with multi-zone potential west central Alberta, in the Peace River Arch area of Alberta and northeastern British Columbia where our expertise and experience is greatest. Our strategy is to deliver base line production and reserve growth on an annual basis from an internal inventory of exploration and development prospects. Yoho will also continue to move forward with the unconventional resource style projects that we have been able to develop over the past year. Complementary and accretive acquisitions will supplement the 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, 2008

In December 2007, the Corporation issued 850,000 Common Shares issued on a "flow-through" basis at the price of \$2.70 per share for total gross proceeds of \$2,295,000 to be incurred on eligible expenditures prior to December 31, 2008. Certain officers and directors of the Corporation acquired 145,000 Common Shares under this private placement.

In December 2007, the expiry dates of 1,000,000 outstanding Common Share purchase warrants issued in May 2005 and 92,226 outstanding Common Share purchase warrants issued in October 2005 were extended from December 13, 2007 to June 13, 2009 and from May 7, 2008 to November 7, 2009, respectively. These warrants, as then amended, were all exercisable for a period of 60 days prior to their respective expiry dates.

On December 31, 2007 the Corporation repaid \$1 million of the principal due to the lender of the subordinated loan facility. This loan, which was due on January 3, 2008, was extended to become due on January 3, 2009. As partial consideration for the loan extension, the Corporation issued to the lender 500,000 Common Share purchase warrants. Each warrant was exercisable into one Common Share issued on a "flow-through" basis at a price of \$2.75 at any time up to June 30, 2008. All the warrants were exercised in June 2008. The balance of the Corporation's indebtedness pursuant to this facility was repaid by the Corporation in June 2008.

On March 11, 2008 at an annual and special meeting of holders of Common Shares, approval was received for the creation of a new class of non-voting shares, namely the Class C Non-Voting Common Shares, the conversion of the Corporation's outstanding 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 Class B Non-Voting Common Share and the cancellation of Yoho's then outstanding Class B Non-Voting Common Shares. Additionally, at the meeting, shareholder approval was received for the employee stock purchase plan whereby for each \$1.00 contributed to the plan by an eligible person, the Corporation would match such contribution by up to \$1.00 for the purpose of acquiring Common Shares for the account of such person (up to a maximum of 5% of such person's annual base salary). Unanimous approval for the conversion of Class B Non-

Voting Common Shares into Common Shares and Class C Non-Voting Common Shares as described above was also received from all holders of Class B Non-Voting Common Shares on March 11, 2008.

On June 4, 2008, Yoho announced that it had acquired approximately 92% of the issued and outstanding common shares of Vision 2000 pursuant to its offer and take-over bid circular dated April 29, 2008, and that it would acquire the remaining shares of Vision 2000 pursuant to the compulsory acquisition procedures of the ABCA. All of the remaining common shares of Vision 2000 not previously acquired by Yoho were acquired by Yoho on June 23, 2008. Aggregate consideration paid by Yoho pursuant to the acquisition of Vision 2000 was \$81,380 in cash and 2,273,237 Common Shares. Vision 2000 was a corporation incorporated pursuant to the laws of the Province of Alberta and had its common shares listed on the TSXV. Yoho amalgamated with Vision 2000 on August 1, 2008.

On September 17, 2008, the Corporation announced its intention to proceed with a normal course issuer bid to purchase for cancellation up to a maximum of 180,000 Common Shares or approximately 1.4% of the Corporation's "public float". A total of 7,300 Common Shares were acquired by Yoho for cancellation pursuant to the normal course issuer bid prior to September 30, 2008.

Year Ended September 30, 2009

On October 15, 2008, the Corporation announced that it had amended the terms of its normal course issuer bid in order to increase the number of Common Shares subject to purchase and cancellation by the Corporation from 180,000 common Shares to up to 600,000 Common Shares or 4.7% of the Corporation's "public float". A total of 500,100 Common Shares were acquired by Yoho for a total consideration of \$764,461 for cancellation pursuant to the normal course issuer bid during the course of the bid. Yoho's normal course issuer bid expired on September 18, 2009.

In May 2009, the expiry dates of 1,000,000 Common Shares purchase warrants originally issued in May 2005 and 92,226 outstanding Common Share purchase warrants originally issued in October 2005 were further extended from June 13, 2009 to May 13, 2010 and from November 7, 2009 to October 7, 2010, respectively. These warrants, as amended, were all exercisable for a period of 60 days prior to their respective expiry dates.

Year Ended September 30, 2010

On November 2, 2009, the Corporation issued 625,000 Common Shares on a "flow-through" basis at \$2.42 per share for total gross proceeds of \$1,512,500.

On March 22, 2010, Yoho completed a bought deal offering with a syndicate of underwriters pursuant to which Yoho issued 1,500,000 Common Shares on a "flow-through" basis at an issue price of \$3.25 per share and 2,875,000 Common Shares at an issue price of \$2.70 per share (including 375,000 Common Shares issued on the full exercise of the over-allotment option granted to the underwriters) for aggregate gross proceeds of \$12,637,500.

On June 30, 2010, Yoho announced that it had acquired 100% of the issued and outstanding common shares of Canoil pursuant to its offer to purchase all of the issued and outstanding common shares of Canoil, which acquisition was carried out as an "exempt take-over bid" under applicable securities laws. The aggregate consideration paid by Yoho pursuant to the acquisition of Canoil was \$6 million in cash and 6,874,880 Common Shares. Yoho amalgamated with Canoil on July 30, 2010.

In the year ended September 30, 2010, 1,024,374 warrants were exercised on a cashless basis. The warrant holders received 82,356 common shares on exercise of their warrants.

On September 14, 2010, Yoho announced the results of a 5,080 metre horizontal well drilled in the Kaybob area of Alberta, which well was targeting the Duvernay shale. The well, operated by Celtic Exploration Ltd., located at 00/15-33-060-20W5 was drilled and cased over a 42 day period for net costs to Yoho of approximately \$1.3 million (\$4.0 million gross). The horizontal lateral of the well was approximately 1,787 metres in length. During the completion of the well, six stages were fractured over a time interval of 10 days. While attempting to fracture the seventh stage, it is believed that a rupture in the casing occurred at the heel portion of the horizontal leg preventing

the fracture of the remaining stages. Starting on September 11, 2010, the well was flow tested with the six stimulated stages, while determining the feasibility of fracturing the remaining stages. After three days on initial testing, the well produced natural gas at a rate of 2.1 MMcf per day and 56° API condensate. As at the date hereof, the well is currently shut-in and awaiting tie-in.

Events Subsequent to September 30, 2010

On December 8, 2010, Yoho completed a bought deal offering with a syndicate of underwriters pursuant to which Yoho issued 1,220,000 Common Shares on a "flow-through" basis at an issue price of \$3.30 per share and 1,820,000 Common Shares at an issue price of \$2.75 per share for aggregate gross proceeds of \$9,031,000. Concurrent with the prospectus offering, the Corporation also completed a non-brokered private placement of 303,030 Common Shares issued on a "flow-through" basis at an issue price of \$3.30 per share for aggregate gross proceeds of \$1,000,000.

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 pursue internal generation of exploration plays that have low to medium risk and multi-zone potential. Yoho intends to maintain a balance between exploration, exploitation and development drilling largely targeting natural gas reserves containing natural gas liquids over the course of the next several years. Yoho will also continue to move forward with the unconventional resource style projects that we have been able to develop over the past year. 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' 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, 2010 for which disclosure is required pursuant to Part 8 of National Instrument 51-102 *Continuous Disclosure Obligations*. See "*General Development of Business – Year Ended September 30, 2010*" for a description of the acquisition of Canoil for which disclosure was not required pursuant to Part 8 of National Instrument 51-102.

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 December 6, 2010. The effective date of the Statement is September 30, 2010 and the preparation date of the Statement was December 6, 2010. 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.

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 and no attempt was made to evaluate possible reserves.

All of our reserves are in Canada and, specifically, in the provinces of Alberta, British Columbia and Saskatchewan as of September 30, 2010.

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.

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, 2010 FORECAST PRICES AND COSTS

RESERVES CATEGORY	RESERVES									
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL RESERVES	
	Gross (MBbl)	Net (MBbl)	Gross (MBbl)	Net (MBbl)	Gross (MMcf)	Net (MMcf)	Gross (MBbl)	Net (MBbl)	Gross (Mboe)	Net (Mboe)
PROVED										
Developed Producing	329	251	141	114	19,609	17,984	534	395	4,273	3,758
Developed Non-Producing	11	11	-	-	1,850	1,655	54	43	373	329
Undeveloped	168	129	-	-	3,772	3,596	85	69	882	798
TOTAL PROVED	<u>508</u>	<u>391</u>	<u>141</u>	<u>114</u>	<u>25,232</u>	<u>23,235</u>	<u>673</u>	<u>507</u>	<u>5,527</u>	<u>4,885</u>
TOTAL PROBABLE	<u>409</u>	<u>315</u>	<u>30</u>	<u>24</u>	<u>14,907</u>	<u>13,263</u>	<u>401</u>	<u>301</u>	<u>3,325</u>	<u>2,850</u>
TOTAL PROVED PLUS PROBABLE	<u>917</u>	<u>706</u>	<u>171</u>	<u>138</u>	<u>40,139</u>	<u>36,498</u>	<u>1074</u>	<u>808</u>	<u>8,852</u>	<u>7,735</u>

**SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF SEPTEMBER 30, 2010
FORECAST PRICES AND COSTS**

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT					Unit Value Before Income Tax Discounted at 10% per Year	
	0% (M\$)	5% (M\$)	10% (M\$)	15% (M\$)	20% (M\$)	\$/boe	\$/Mcfe
PROVED							
Developed Producing	108,227	84,306	69,218	58,938	51,520	18.42	3.07
Developed Non-Producing	8,930	7,322	6,154	5,274	4,593	18.70	3.12
Undeveloped	20,835	14,055	9,980	7,329	5,497	12.51	2.08
TOTAL PROVED	137,992	105,683	85,352	71,541	61,610	17.47	2.91
TOTAL PROBABLE	98,380	62,240	40,919	29,748	22,641	14.36	2.39
TOTAL PROVED PLUS PROBABLE	236,372	165,922	126,271	101,289	84,251	16.32	2.72

**SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF SEPTEMBER 30, 2010
FORECAST PRICES AND COSTS**

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAXES DISCOUNTED AT				
	0% (M\$)	5% (M\$)	10% (M\$)	15% (M\$)	20% (M\$)
PROVED					
Developed Producing	100,695	79,728	66,292	56,989	50,179
Developed Non-Producing	6,697	5,638	4,861	4,266	3,796
Undeveloped	15,626	10,445	7,332	5,307	3,907
TOTAL PROVED	123,017	95,811	78,485	66,563	57,882
TOTAL PROBABLE	73,879	44,985	30,365	21,919	16,552
TOTAL PROVED PLUS PROBABLE	196,896	140,796	108,849	88,482	74,434

**TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
AS OF SEPTEMBER 30, 2010
FORECAST PRICES AND COSTS**

RESERVES CATEGORY	REVENUE (M\$)	ROYALTIES (M\$)	OPERATING COSTS (M\$)	CAPITAL DEVELOP- MENT COSTS (M\$)	WELL ABANDON- MENT COSTS (M\$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M\$)	INCOME TAXES (M\$)	FUTURE NET REVENUE AFTER INCOME TAXES (M\$)
Total Proved Reserves	263,259	38,279	73,505	10,411	3,073	137,992	14,975	123,017
Total Probable Proved Plus Reserves	190,595	29,846	47,030	14,588	750	98,380	24,502	73,879
Total Proved Reserves	453,855	68,125	120,535	24,999	3,823	236,372	39,476	196,896

**FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF SEPTEMBER 30, 2010
FORECAST PRICES AND COSTS**

RESERVES CATEGORY	PRODUCTION GROUP	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)	12,141	40.04	6.67
	Heavy Oil (including solution gas and other by-products)	3,623	29.85	4.98
	Natural Gas (including by-products but excluding solution gas from oil wells)	52,881	16.00	2.67
	Non-conventional oil & gas activities	573	20.63	3.44
	Total	69,218	18.42	3.07
Total Proved	Light and Medium Crude Oil (including solution gas and other by-products)	17,479	38.46	6.41
	Heavy Oil (including solution gas and other by-products)	3,634	29.95	4.99
	Natural Gas (including by-products but excluding solution gas from oil wells)	61,297	15.06	2.51
	Non-conventional oil & gas activities	2,941	12.37	2.06
	Total	85,352	17.47	2.91
Total Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	29,338	35.48	5.91
	Heavy Oil (including solution gas and other by-products)	4,214	28.71	4.78
	Natural Gas (including by-products but excluding solution gas from oil wells)	82,643	13.49	2.25
	Non-conventional oil & gas activities	10,076	15.91	2.65
	Total	126,271	16.32	2.72

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.

RESERVES RECONCILIATION

RECONCILIATION OF COMPANY GROSS RESERVES
AS OF SEPTEMBER 30, 2010
FORECAST PRICES AND COSTS

RESERVES CATEGORY	LIGHT AND MEDIUM OIL			HEAVY OIL		
	Gross Proved (MBbl)	Gross Probable (MBbl)	Gross Proved Plus Probable (MBbl)	Gross Proved (MBbl)	Gross Probable (MBbl)	Gross Proved Plus Probable (MBbl)
September 30, 2009	103	107	210	128	28	155
Discoveries	-	-	-	-	-	-
Extensions & Improved Recovery	14	46	60	-	-	-
Technical Revisions	(8)	(15)	(22)	51	2	53
Acquisitions	436	271	707	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	(38)	-	(38)	(37)	-	(37)
September 30, 2010	508	409	917	141	30	171

RESERVES CATEGORY	NATURAL GAS LIQUIDS			TOTAL GAS		
	Gross Proved (MBbl)	Gross Probable (MBbl)	Gross Proved Plus Probable (MBbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)
September 30, 2009	319	136	456	17,628	9,657	27,284
Discoveries	23	23	46	414	121	535
Extensions & Improved Recovery	283	128	410	8,840	5,204	14,044
Technical Revisions	96	105	201	281	(1,213)	(933)
Acquisitions	19	10	28	2,066	1,158	3,224
Dispositions	-	-	-	(20)	(19)	(39)
Economic Factors	-	-	-	-	-	-
Production	(66)	-	(66)	(3,976)	-	(3,796)
September 30, 2010	673	401	1,074	25,232	14,907	40,139

RESERVES CATEGORY	CONVENTIONAL NATURAL GAS			COAL BED METHANE		
	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)
September 30, 2009	17,578	9,457	27,035	50	199	250
Discoveries	-	-	-	414	121	535
Extensions & Improved Recovery	8,237	3,752	11,989	603	1,452	2,055
Technical Revisions	275	(1,217)	(942)	6	3	9
Acquisitions	2,066	1,158	3,224	-	-	-
Dispositions	(20)	(19)	(39)	-	-	-
Economic Factors	-	-	-	-	-	-
Production	(3,974)	-	(3,974)	(2)	-	(2)
September 30, 2010	24,161	13,132	37,292	1,071	1,775	2,846

RESERVES CATEGORY	BOE		
	Gross Proved (Mboe)	Gross Probable (Mboe)	Gross Proved Plus Probable (Mboe)
September 30, 2009	3,488	1,881	5,369
Discoveries	92	43	135
Extensions & Improved Recovery	1,770	1,041	2,811
Technical Revisions	186	(112)	74
Acquisitions	799	474	1,273
Dispositions	(4)	(3)	(7)
Economic Factors	-	-	-
Production	(803)	-	(803)
September 30, 2010	5,527	3,325	8,852

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 of our royalty interests;
- (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 (see the discussion of "Economic Assumptions" below).

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, 2010, 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, 2010, inflation and exchange rates utilized in the GLJ Report were as follows:

**SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
AS OF SEPTEMBER 30, 2010
FORECAST PRICES AND COSTS**

Year	Crude Oil				Natural Gas Liquids	
	WTI Cushing Oklahoma (\$US/Bbl)	Edmonton Par Price 40 API (\$Cdn/Bbl)	Hardisty Heavy 12 API (\$Cdn/Bbl)	Edmonton Propane (\$/Bbl)	Edmonton Butane (\$/Bbl)	Edmonton Pentanes Plus (\$/Bbl)
2010 Q4	80.00	83.26	63.90	49.96	64.11	84.93
2011	83.00	86.42	65.24	54.45	66.54	88.15
2012	86.00	89.58	65.33	56.43	68.98	91.37
2013	89.00	92.74	65.26	58.42	71.41	94.59
2014	92.00	95.90	67.52	60.42	73.84	97.82
2015	93.84	97.84	68.90	61.64	75.33	99.79
2016	95.72	99.81	70.32	62.88	76.85	101.81
2017	97.64	101.83	71.76	64.15	78.41	103.86
2018	99.59	103.88	73.22	65.45	79.99	105.96
2019	101.58	105.98	74.72	66.77	81.60	108.10

Year	Natural Gas		INFLATION RATES ⁽¹⁾ %/Year	EXCHANGE RATE ⁽²⁾ (\$US/\$Cdn)
	AECO –C Spot (\$Cdn/MMBtu)	Westcoast Station 2 (\$Cdn/MMBtu)		
2010 Q4	4.00	3.80	2.0	0.95
2011	4.37	4.17	2.0	0.95
2012	5.05	4.85	2.0	0.95
2013	5.74	5.54	2.0	0.95
2014	6.32	6.12	2.0	0.95
2015	6.79	6.59	2.0	0.95
2016	7.16	6.96	2.0	0.95
2017	7.47	7.27	2.0	0.95
2018	7.63	7.43	2.0	0.95
2019	7.81	7.61	2.0	0.95

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, 2010, were \$4.14 per Mcf for natural gas, \$57.77 per Bbl for light oil and natural gas liquids, and \$61.79 per Bbl for heavy oil.

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 2011 and 2012 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 undeveloped reserves are attributed in accordance with NI 51-101. There are proved undeveloped reserves assigned to development drilling at Sweeney, Alberta, with the remaining proved undeveloped reserves assigned for drilling at Kaybob, Alberta and at Buick Creek, British Columbia. It is anticipated that these reserves will be developed over the following two years.

Company 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
Prior	-	-	-	-	1,300	1,300
2008	-	-	-	-	824	824
2009	-	-	-	-	488	976
2010	168	168	-	-	3,134	3,134

Proved Undeveloped Reserves	NATURAL GAS LIQUIDS (MBbl)		COAL BED METHANE (MMcf)		BOE (MBoe)	
	First Attributed	Total At Year End	First Attributed	Total At Year End	First Attributed	Total At Year End
Prior	17	17	-	-	233	233
2008	14	14	-	-	153	152
2009	1	1	-	-	82	171
2010	85	85	594	638	874	881

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
Prior	-	-	-	-	766	856
2008	25	25	-	-	958	1,070
2009	-	-	-	-	2,257	2,532
2010	193	193	-	-	4,933	5,733

Probable Undeveloped Reserves	NATURAL GAS LIQUIDS (MBbl)		COAL BED METHANE (MMcf)		BOE (MBoe)	
	First Attributed	Total At Year End	First Attributed	Total At Year End	First Attributed	Total At Year End
Prior	12	12	-	-	164	179
2008	8	8	-	-	167	186
2009	32	32	-	-	408	487
2010	198	210	1,449	1,646	1,455	1,640

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.

Year	Forecast Prices and Costs	
	Proved Reserves	Proved Plus Probable Reserves
	(M\$)	(M\$)
2010	2,268	2,730
2011	5,310	16,919
2012	2,833	4,549
2013	-	248
2014	-	-
2015	-	-
2016	-	-
2017	-	-
2018	-	-
2019	-	430
Remainder	-	124
Total Undiscounted (all years)	10,411	24,999
Total discounted 10%	9,582	22,710

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 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, 2010. Unless otherwise specified, well count information is as at September 30, 2010.

Western Peace River Arch: Yoho has a variety of exploration targets within the Western Peace River Arch in the Province of Alberta. The main targets for exploration are the Triassic aged wedge of sediments that subcrop throughout the area, including the Doig, Halfway, Boundary Lake, Charlie Lake and Baldonnel formations and the Cretaceous aged sediments, including the Gething and Bluesky formations. The Corporation has also participated in several deeper tests targeting the Devonian Wabamun formation utilizing three dimensional seismic. The Wabamun, which is a higher risk target, also has higher potential rewards.

- *Basset Lake:* The Corporation holds a 50% working interest in 19 producing Bluesky gas wells.
- *Boundary Lake:* Yoho has interests ranging from 26% to 60% in eight producing gas wells.
- *Clear Hills:* We have interests ranging from 40% to 50% in six producing gas wells.
- *Manir:* We have a 55% interest in two producing oil wells.
- *Sinclair:* The Corporation holds interests from 11% to 100% in three producing gas wells.
- *Spirit River:* Yoho has interests ranging from 2.5% to 50% in ten producing gas wells.
- *Sweeney:* The Corporation has a 40% working interest in six producing oil wells and two gas wells.
- *Worsley:* We have a 50% interest in two producing gas wells and interests ranging from 20% to 50% in five producing oil wells.

Northeastern British Columbia: The area is similar geologically to the Western Peace River Arch and makes a natural extension to the successful results achieved in the Western Peace River Arch area. The primary targets in the area are the Lower Mannville, Dunlevy and Bluesky formations and the Triassic formations of the Halfway, Baldonnel and Charlie Lake. Most of the targets Yoho has identified in this area are less than 1,200 metres in depth.

- *Buick Creek:* Yoho has varying interests in 15 producing gas wells with interest ranging from 5% to 58% in 14 wells and a 100% interest in one well.

- *Mike*: Yoho's interests vary from 85% to 100% in 11 producing gas wells.

West Central Alberta: Another core area for Yoho is in West Central Alberta. The main targets in this area are the Spirit River and Gething Formations within the Cretaceous period and the Devonian Duvernay formation.

- *Kaybob*: The Company has interests ranging from 1% to 96% in 18 producing gas wells.
- *Windfall*: Yoho has a 50% interest in four producing gas wells.

The following table indicates our average daily production before deduction of royalties and including royalty interests for the year ended September 30, 2010.

	Light and Medium Crude Oil & NGLs	Heavy Oil	Gas
	(Bbl/d)	(Bbl/d)	(Mcf/d)
Basset Lake	4	-	616
Boundary Lake	8	-	2,226
Buick Creek	28	-	1,550
Kaybob	36	-	829
Knappen	-	-	416
Mike	3	-	1,817
Sinclair	7	-	652
Spirit River	72	-	759
Windfall	36	-	956
Worsley	13	-	304
Other	89	102	1,101
Total	296	102	11,226

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, 2010.

	Natural Gas Wells				Oil Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	157	33.2	62	21.6	71	7.9	30	5.3
British Columbia	56	18.1	25	6.8	6	0.1	5	1.1
Saskatchewan	-	-	-	-	3	1.1	6	2.2
Total	213	51.3	87	28.4	80	9.1	41	8.6

Properties with no Attributable Reserves

The following table sets out our undeveloped land holdings as September 30, 2010.

	Undeveloped Acres	
	Gross	Net
Alberta	169,155	102,863
British Columbia	83,331	62,595
Total	252,486	165,458

Yoho has no work commitments on these lands. We expect that rights to explore, develop and exploit 48,160 net acres of our undeveloped land holdings, absent further action, will expire by September 30, 2011.

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, 2010, Yoho did not have any material commitments to buy or sell natural gas or crude oil production:

Contract	Term	Volume	Pricing Point	Price
Costless Collar	Apr 1/10 – Dec 31/10	3,000 GJ per day	AECO	\$5.00 - \$5.94 per GJ
Fixed Price	July 1/10 – Oct 31/10	300 GJ per day	NA	\$5.50 per GJ

As at the date hereof, Yoho has the following financial derivative contract outstanding:

Contract	Term	Volume	Pricing Point	Price
Costless Collar	Apr 1/10 – Dec 31/10	3,000 GJ per day	AECO	\$5.00 - \$5.94 per GJ

Additional Information Concerning Abandonment and Reclamation Costs

Estimated future abandonment and reclamation costs related to well abandonment 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 there from. No allowance was made, however, for reclamation of wellsites or 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 97.4 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 Corporation liability associated with the wells not assigned reserves by GLJ, pipelines and facility reclamation costs, which was estimated to be \$4.2 million (\$2.6 million discounted at 10%), was not deducted in estimating future net revenue. We estimate over the next three years a total of \$1.4 million (\$1.2 million discounted at 10%) will be incurred on abandonment and reclamation costs.

Tax Horizon

Yoho was not required to pay any cash incomes taxes for the year ended September 30, 2010. 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 2014 or later.

Capital Expenditures

The following table summarizes capital expenditures related to our activities for the year ended September 30, 2010.

Property acquisition costs:	
Proved properties	\$ -
Unproved properties	2,587,440
Exploration costs	7,675,389
Development costs	12,337,010
Total	<u>\$ 22,599,839</u>

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, 2010.

	Exploratory Wells		Development Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Oil	-	-	-	-	-	-
Natural Gas	2	1.3	14	7.2	16	8.5
Service	-	-	-	-	-	-
Dry	1	1.0	-	-	1	1.0
Total	<u>3</u>	<u>2.3</u>	<u>14</u>	<u>7.2</u>	<u>17</u>	<u>9.5</u>

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 proceeding table is Kaybob.

	LIGHT AND MEDIUM OIL (Bbl/d)	HEAVY OIL (Bbl/d)	NATURAL GAS (Mcf/d)	NATURAL GAS LIQUIDS (Bbl/d)	TOTAL OIL EQUIVALENT (boe/d)
Total Proved					
Kaybob	9	-	2,744	150	617
Other Properties	250	95	9,575	147	2,088
Total Proved Daily Production	<u>259</u>	<u>95</u>	<u>12,319</u>	<u>297</u>	<u>2,705</u>

	LIGHT AND MEDIUM OIL (Bbl/d)	HEAVY OIL (Bbl/d)	NATURAL GAS (Mcf/d)	NATURAL GAS LIQUIDS (Bbl/d)	TOTAL OIL EQUIVALENT (boe/d)
Total Probable					
Total Probable Daily Production	-	-	31	2	7
Other Properties	3	1	182	1	36
Total Probable Daily Production	<u>3</u>	<u>1</u>	<u>213</u>	<u>3</u>	<u>43</u>

	LIGHT AND MEDIUM OIL (Bbl/d)	HEAVY OIL (Bbl/d)	NATURAL GAS (Mcf/d)	NATURAL GAS LIQUIDS (Bbl/d)	TOTAL OIL EQUIVALENT (boe/d)
Total Proved and Probable					
Kaybob	10	-	2,775	152	624
Other Properties	253	96	9,757	148	2,123
Total Proved and Probable Daily Production	<u>262</u>	<u>96</u>	<u>12,532</u>	<u>300</u>	<u>2,747</u>

Production History and Prices Received - Fiscal 2010

The following tables summarize certain information for our year ended September 30, 2010 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)	11,358	10,899	11,578	11,057
Light oil and NGL (Bbl/d)	243	274	242	428
Heavy oil (Bbl/d)	100	110	99	98
BOE (boe/d)	2,236	2,200	2,270	2,368

	Natural Gas (\$/Mcf)	Light Oil & NGLs (\$/Bbl)	Heavy Oil (\$/Bbl)	BOE (\$/boe)
Q1				
Sales Price	4.43	52.27	58.64	30.79
Royalties	(0.69)	(4.65)	(10.52)	(4.46)
Operating Costs	(0.85)	(2.29)	(13.73)	(5.17)
Processing	(0.80)	-	-	(4.08)
Operating Netback	2.09	45.33	34.39	17.08

	Natural Gas (\$/Mcf)	Light Oil & NGLs (\$/Bbl)	Heavy Oil (\$/Bbl)	BOE (\$/boe)
Q2				
Sales Price	4.84	61.48	60.06	34.63
Royalties	(0.97)	(3.15)	(10.74)	(5.72)
Operating Costs	(0.87)	(1.60)	(12.42)	(5.15)
Processing	(0.81)	-	-	(4.00)
Operating Netback	2.19	56.73	36.90	19.76

	Natural Gas (\$/Mcf)	Light Oil & NGLs (\$/Bbl)	Heavy Oil (\$/Bbl)	BOE (\$/boe)
Q3				
Sales Price	3.80	59.31	51.98	27.96
Royalties	(0.25)	(1.07)	(26.10)	(2.51)
Operating Costs	(0.77)	(2.33)	(12.34)	(4.72)
Processing	(0.94)	-	-	(4.80)
Operating Netback	1.84	55.91	13.56	15.93

	Natural Gas (\$/Mcf)	Light Oil & NGLs (\$/Bbl)	Heavy Oil (\$/Bbl)	BOE (\$/boe)
Q4				
Sales Price	3.53	57.72	76.68	30.08
Royalties	(0.32)	(8.01)	(7.11)	(3.01)
Operating Costs	(0.94)	(10.02)	(6.50)	(6.47)
Processing	(0.89)	-	-	(4.13)
Operating Netback	1.43	39.69	63.05	16.47

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, transportation, and marketing) as a result of legislation enacted by various levels of government and with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta, British Columbia and Saskatchewan, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these regulations or controls will affect the Corporation's operations in a manner materially different than they will affect other oil and natural gas companies of similar size. All current legislation is a matter of public record and 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.

Pricing and Marketing

Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance, and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "NEB"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

Natural Gas

The price of the vast majority of natural gas produced in western Canada is now determined through the liquid market established at the Alberta "NIT" hub rather than through direct negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m³/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

The governments of Alberta, British Columbia and Saskatchewan also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements, and market considerations.

Pipeline Capacity

As a result of pipeline expansions over the past several years, there is ample pipeline capacity to accommodate current production levels of oil and natural gas in western Canada and pipeline capacity does not generally limit the ability to produce and market such production.

The North American Free Trade Agreement

The North American Free Trade Agreement ("NAFTA") among the governments of Canada, the United States and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada United States Free Trade Agreement. 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 domestic use (based upon 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 voluntary measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. All three signatory countries are prohibited from imposing minimum or maximum export or import price requirements, provided, in the case of export price requirements, that any prohibition in any circumstances in which any other form of quantitative restriction is applied is prohibited, and in the case of import-price requirements, that such requirements do not apply with respect to enforcement of countervailing and anti-dumping orders and undertakings.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector by 2010 and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes, minimize disruption of contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports.

Royalties and Incentives

General

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

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

Alberta

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

On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" ("NRF") containing the Government's proposals for Alberta's new royalty regime which were subsequently implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*. The NRF took effect on January 1, 2009. On March 11, 2010, the Government of Alberta announced changes to Alberta's royalty system intended to increase Alberta's competitiveness in the upstream oil and natural gas sectors, which changes included a decrease in the maximum royalty rates for conventional oil and natural gas production effective for the January 2011 production month. Royalty curves incorporating the changes announced on March 11, 2010 were released on May 27, 2010.

With respect to conventional oil, the NRF eliminated the classification system used by the previous royalty structure which classified oil based on the date of discovery of the pool. Under the NRF, 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. Royalty rates for conventional oil under the NRF ranged from 0-50%, an increase from the previous maximum rates of 30-35% depending on the vintage of the oil, and rate caps were set at \$120 per barrel. Effective January 1, 2011, the maximum royalty payable under the NRF was reduced to 40%. The royalty curve for conventional oil announced on May 27, 2010 amends the price component of the conventional oil royalty formula to moderate the increase in the royalty rate at prices higher than \$535/m³ compared to the previous royalty curve.

Royalty rates for natural gas under the NRF are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Royalty rates for natural gas under the NRF ranged from 5-50%, an increase from the previous maximum rates of 5-35%, and rate caps were set at \$17.75/GJ. Effective January 1, 2011, the maximum royalty payable under the NRF was reduced to 36%. The royalty curve for natural gas announced on May 27, 2010 amends the price component of the natural gas royalty formula to moderate the increase in the royalty rate at prices higher than \$5.25/GJ compared to the previous royalty curve.

Oil sands projects are also subject to the NRF. Prior to payout, 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: 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. An oil sands project reaches payout when its cumulative revenue exceeds its cumulative costs. Costs include specified allowed capital and operating costs related to the project plus a specified return allowance. As part of the implementation of the NRF, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the NRF.

In August 2006, the Government of Alberta introduced the Innovative Energy Technologies Program (the "**IETP**"), which has a stated objective of promoting producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP is backed by a \$200 million funding commitment over a five-year period beginning April 1, 2005 and provides royalty adjustments to specific pilot and demonstration projects that utilize innovative technologies to increase recovery from existing reserves.

On April 10, 2008, the Government of Alberta introduced two new royalty programs to be implemented along with the NRF and intended to encourage the development of deeper, higher cost oil and gas reserves. A five-year program for conventional oil exploration wells over 2,000 metres provides qualifying wells with up to a \$1 million or 12 months of royalty relief, whichever comes first, and a five-year program for natural gas wells deeper than 2,500 metres provides a sliding scale royalty credit based on depth of up to \$3,750 per metre. On May 27, 2010, the natural gas deep drilling program was amended, retroactive to May 1, 2010, by reducing the minimum qualifying depth to 2,000 metres, removing a supplemental benefit of \$875,000 for wells exceeding 4,000 metres that are spud subsequent to that date, and including wells drilled into pools drilled prior to 1985, among other changes.

On November 19, 2008, in response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The 5-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well's life when production rates are expected to be the highest. Under this new program, companies drilling new natural gas or conventional oil deep wells (between 1,000 and 3,500 m) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. Pursuant to the changes made to Alberta's royalty structure announced on March 11, 2010, producers will only be able to elect to adopt the transitional royalty rates prior to January 1, 2011 and producers that have already elected to adopt the transitional royalty rates as of that date will be permitted to switch to Alberta's conventional royalty structure. On December 31, 2013, all producers operating under the transitional royalty rates will automatically become subject to Alberta's conventional royalty structure. The revised royalty curves for conventional oil and natural gas will not be applied to production from wells operating under the transitional royalty rates.

On March 3, 2009, the Government of Alberta announced a three-point incentive program in order to stimulate new and continued economic activity in Alberta. The program introduced a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program, both applying to conventional oil or natural gas wells drilled between April 1, 2009 and March 31, 2010. The drilling royalty credit provides up to a \$200 per metre royalty credit for new wells and is primarily expected to benefit smaller producers since the maximum credit available will be determined using the company's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2010, favouring smaller producers with lower activity levels. The new well incentive program initially applied to wells that began producing conventional oil or natural gas between April 1, 2009 and March 31, 2010 and provided for a maximum 5% royalty rate for the first 12 months of production on a maximum of 50,000 barrels of oil or 500 MMcf of natural gas. In June, 2009, the Government of Alberta announced the extension of these two incentive programs for one year to March 31, 2011. On March 11, 2010, the Government of Alberta announced that the incentive program rate of 5% for the first 12 months of production would be made permanent, with the same volume limitations.

In addition to the foregoing, on May 27, 2010, in conjunction with the release of the new royalty curves, the Government of Alberta announced a number of new initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the "**Emerging Resources and Technologies Initiative**"). Specifically:

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;
- Shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;
- Horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010;
- 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, retroactive to wells that commenced drilling on or after May 1, 2010.

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

In addition to the foregoing, Alberta currently maintains a royalty reduction program for low productivity oil and oil sands wells, a royalty adjustment program for deep marginal gas wells and a royalty exemption for re-entry wells, among others.

British Columbia

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, currently at a rate of \$7.50 per hectare, 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 based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 ("old oil"), between October 31, 1975 and June 1, 1998 ("new oil"), or after June 1, 1998 ("third-tier oil"). 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 as an incentive for the production and marketing of natural gas which might otherwise have been flared.

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. For natural gas, the freehold production tax 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.

As at the beginning of 2009, British Columbia maintained a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity wells. These include both royalty credit and royalty reduction programs, including the following:

- *Summer Royalty Credit Program* providing a royalty credit of 10% of drilling and completion costs up to \$100,000 for wells drilled between April 1 and November 30 of each year, intended to increase summer drilling activity, employment and business opportunities in northeastern British Columbia;

- *Deep Royalty Credit Program* providing a royalty credit equal to approximately 23% of 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 2,300 metres spud between December 1, 2003 and September 1, 2009;
- *Deep Re-Entry Royalty Credit Program* providing royalty credits for deep re-entry wells with a true vertical depth greater than 2,300 metres and a re-entry date subsequent to December 1, 2003;
- *Deep Discovery Royalty Credit Program* providing the lesser of a 3-year royalty holiday or 283,000,000 m³ 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 m³ 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 royalty breaks for low productivity natural gas wells with average monthly production under 25,000 m³ during the first 12 production months and average daily production less than 23 m³ for every metre of marginal well depth;
- *Ultra-Marginal Royalty Reduction Program* providing additional royalty breaks for low productivity shallow natural gas wells with a true vertical depth of less than 2,300 metres, average monthly production under 60,000 m³ during the first 12 production months and average daily production less than 11.5 m³ (development wells) or 17 m³ (exploratory wildcat wells) for every 100 metres of marginal well depth;
- *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 event on either Crown or freehold land and completed in a new pool discovery 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 m³ of production, whichever comes first.

On March 2, 2009, the Government of British Columbia announced the 2009 Infrastructure Royalty Credit Program (the "**Infrastructure Royalty Credit Program**") which allocates \$120 million in royalty credits for oil and gas companies. The Infrastructure Royalty Credit Program provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to improve, or make possible, the access to new and underdeveloped oil and gas areas. On March 10, 2010, the Government of British Columbia announced the same level of funding for the 2010 Infrastructure Royalty Credit Program.

On August 6, 2009, the Government of British Columbia announced an oil and gas stimulus package designed to attract investment in and create economic benefits for British Columbia. The stimulus package includes four royalty initiatives related primarily to natural gas drilling and infrastructure development. Natural gas wells spudded within the 10-month period from September 1, 2009 to June 30, 2010 and brought on production by December 31, 2010 qualify for a 2% royalty rate for the first 12 months of production, beginning from the first month of production for the well (the "**Royalty Relief Program**"). British Columbia's existing Deep Royalty Credit Program was permanently amended for wells spudded after August 31, 2009 by increasing the royalty deduction on deep drilling for natural gas by 15% and extending the program to include horizontal wells drilled to depths of between 1,900 and 2,300 metres. Wells spud between September 1, 2009 and June 30, 2010 may qualify for both the Royalty Relief Program and the Deep Royalty Credit Program but will only receive the benefits of one program at a time. An

additional \$50 million was also allocated to be distributed through the Infrastructure Royalty Credit Program to stimulate investment in oilfield-related road and pipeline construction.

Saskatchewan

In Saskatchewan, the amount payable as a royalty 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 classified as "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil", "third tier oil", "new oil" and "old oil") depend on the finished drilling date of a well and are applied to each of the three crude oil types slightly differently. Heavy oil is classified as third tier oil (having a finished drilling date on or after January 1, 1994 and before October 1, 2004), fourth tier oil (having a finished drilling date on or after October 1, 2002) or new oil (not classified as either third tier oil or fourth tier oil). Southwest designated oil uses the same definitions of third and fourth tier oil but 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 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, whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil. Where average wellhead prices are below the established base prices of \$100 per m³ for third and fourth tier oil and \$50 per m³ 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 royalty in respect of natural gas production is determined by a sliding scale based on a reference price (which is the greater of the amount obtained by the producer and a prescribed minimum price), the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. Like conventional oil, natural gas is classified as "non-associated gas" or "associated gas" and royalty rates are determined according to the finished drilling date of the respective well. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on natural gas produced in association with oil is less than on non-associated natural gas. 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 more than 3,500 m³ of gas for every m³ 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.

As with conventional oil production, base prices 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 \$50 per thousand m³ for third and fourth tier gas and \$35 per thousand m³ 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 well-head 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 Government of Saskatchewan currently provide 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 and freehold tax rates on incentive volumes of 8,000 m³ for deep development vertical oil wells, 4,000 m³ for non-deep exploratory vertical oil wells and 16,000 m³ for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations);
- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 m³ for qualifying exploratory gas wells;
- *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 6,000 m³ for non-deep horizontal oil wells and 16,000 m³ for deep horizontal oil wells (more than 1,700 metres or within certain formations);
- *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002* treating incremental production from waterflood projects as fourth tier oil for the purposes of royalty calculation;
- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005* providing Crown royalty and freehold tax determinations based in part on the profitability of enhanced recovery projects pre- and post-payout; and
- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing on or after April 1, 2005* providing a Crown royalty of 1% of gross revenues on enhanced oil recovery projects pre-payout and 20% post-payout and a freehold production tax of 0% on operating income from enhanced oil recovery projects pre-payout and 8% post-payout.

In 1975, the Government of Saskatchewan introduced a Royalty Tax Rebate ("RTR") as a response to the Government of Canada disallowing crown royalties and similar taxes as a deductible business expense for income tax purposes. As of January 1, 2007, the remaining balance of any unused RTR will be limited in its carry forward to seven years since the Government of Canada's initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial taxable income. Saskatchewan's RTR will be wound down as a result of the Government of Canada's plan to reintroduce full deductibility of provincial resource royalties for corporate income tax purposes.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms from two years, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned 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 and Saskatchewan has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license. On March 29, 2007, British Columbia's policy of deep rights reversion was expanded for new leases to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of their primary term.

In Alberta, the NRF includes a policy of "shallow rights reversion" which provides, for the first time in western Canada, for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights,

which will be implemented three years from the date of the notice. The order in which these agreements will receive the reversion notice will depend on their vintage and location, with the older leases and licenses receiving reversion notices first beginning in January 2011. Leases and licences that were granted prior to January 1, 2009 but continued after that date will not be subject to shallow rights reversion until they reach the end of their primary term and are continued (at which time deep rights reversion will be applied); thereafter, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

In December, 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans. The *Alberta Land Stewardship Act* (the "**ALSA**") was proclaimed in force in Alberta on October 1, 2009, providing the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA are deemed to be legislative instruments equivalent to regulations and are 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, approvals and authorizations in order 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. Although no regional plans have been established under the ALSA, the planning process is underway for the Lower Athabasca Region (which contains the majority of oil sands development) and the South Saskatchewan Region. While the potential impact of the regional plans established under the ALSA cannot yet be determined, it is clear that such regional plans may have a significant impact on land use in Alberta and may affect the oil and gas industry.

Climate Change Regulation

Federal

In December 2002, the Government of Canada ratified the Kyoto Protocol ("**Kyoto Protocol**"), which requires a reduction in greenhouse gas emissions by signatory countries between 2008 and 2012. The Kyoto Protocol officially came into force on February 16, 2005 and commits Canada to reduce its greenhouse gas emissions levels to 6% below 1990 "business-as-usual" levels by 2012.

In anticipation of the expiry of the Kyoto Protocol in 2012, government leaders and representatives from approximately 170 countries met in Copenhagen, Denmark from December 6 to 18, 2009 (the "**Copenhagen Conference**") to attempt to negotiate a successor to the Kyoto Protocol. The primary result of the Copenhagen Conference was the Copenhagen Accord, which represents a broad political consensus rather than a binding

international treaty like the Kyoto Protocol and has not been endorsed by all participating countries. The Copenhagen Accord reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. Although certain countries, including Canada, have committed to reducing their emissions individually or jointly by at least 80% by 2050, the Copenhagen Accord does not establish binding GHG emissions reduction targets. The Copenhagen Accord calls for a review and implementation of its stated goals by 2016.

In response to the Copenhagen Accord, the Government of Canada indicated on January 29, 2010 that it will seek to achieve a 17% reduction in greenhouse gas emissions from 2005 levels by 2020. This goal is similar to the goal expressed in previous policy documents which are discussed below.

On February 14, 2007, the House of Commons passed Bill C-288, *An Act to ensure Canada meets its global climate change obligations under the Kyoto Protocol*. The resulting *Kyoto Protocol Implementation Act* came into force on June 22, 2007. Its stated purpose is to "ensure that Canada takes effective and timely action to meet its obligations under the Kyoto Protocol and help address the problem of global climate change." It requires the federal Minister of the Environment to, among other things, produce an annual climate change plan detailing the measures to be taken to ensure Canada meets its obligations under the Kyoto Protocol. It also authorizes the establishment of regulations respecting matters such as emissions limits, monitoring, trading and enforcement.

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both greenhouse gases 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**"). Although draft regulations for the implementation of the Updated Action Plan were intended to be published in the fall of 2008 and become binding on January 1, 2010, no such regulations have been proposed to date. Further, representatives the Government of Canada have recently indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to greenhouse gas emissions regulation, which may include an absolute cap on emissions combined with allowances to be used for compliance that may be partially auctioned off to regulated entities. It is also unclear whether the approach adopted by the United States will provide for the payment into a technology fund as a compliance mechanism, as is currently permitted in Alberta and by the Updated Action Plan. As a result, many provisions of the Updated Action Plan, described below, are expected to be significantly modified.

The stated goal of the Updated Action Plan, as currently drafted, is to reduce greenhouse gas emissions to 20% below 2006 levels by 2020 and 60-70% by 2050. As noted above, the goal has now been modified by the Government of Canada. The Updated Action Plan outlines emissions intensity-based targets which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets applied to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets.

The Updated Action Plan makes a distinction between "Existing Facilities" and "New Facilities". For Existing Facilities, the Updated Action Plan requires an emissions intensity reduction of 18% below 2006 levels by 2010 followed by a continuous annual emissions intensity improvement of 2%. "New Facilities" are defined as facilities beginning operations in 2004 and include both greenfield facilities and major facility expansions that (i) result in a 25% or greater increase in a facility's physical capacity, or (ii) involve significant changes to the processes of the facility. New Facilities will be given a 3-year grace period during which no emissions intensity reductions will be required. Targets requiring an annual 2% emissions intensity reduction will begin to apply in the fourth year of commercial operation of a New Facility. Further, emissions intensity targets for New Facilities will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time. The method of applying this cleaner fuel standard has not yet been determined. In addition, the Updated Action Plan indicates that targets for the adoption of carbon capture and storage ("CCS") technologies will be developed for oil sands in-situ facilities, upgraders and coal-fired power generators that begin operations in 2012 or later. These targets will become operational in 2018, although the exact nature of the targets has not yet been determined.

Given the large number of small facilities within the upstream oil and gas and natural gas pipeline sectors, facilities within these sectors will only be subject to emissions intensity targets if they meet certain minimum emissions thresholds. That threshold will be (i) 50,000 tonnes of CO₂ equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO₂ equivalents per facility per year for the upstream oil and gas facility; and (iii) 10,000 boe/d/company. These regulatory thresholds are significantly lower than the regulatory threshold in force in Alberta, discussed below. In all other sectors governed by the Updated Action Plan, all facilities will be subject to regulation.

Four separate compliance mechanisms are provided for in the Updated Action Plan in respect of the above targets: Technology Fund contributions, offset credits, clean development credits and credits for early action. Regulated entities will be able to use Technology Fund contributions to meet their emissions intensity targets. The contribution rate for Technology Fund contributions will increase over time, beginning at \$15 tonnes per CO₂ equivalent for the 2010-12 period, rising to \$20 in 2013, and thereafter increasing at the nominal rate of GDP growth. Maximum contribution limits will also decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce greenhouse gas emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as described above.

The offset system is intended to encourage emissions reductions from activities outside of the regulated sphere, allowing non-regulated entities to participate in and benefit from emissions reduction activities. In order to generate offset credits, project proponents must propose and receive approval for emissions reduction activities that will be verified before offset credits will be issued to the project proponent. Those credits can then be sold to regulated entities for use in compliance or non-regulated purchasers that wish to either purchase the offset credits for cancellation or banking for future use or sale.

Under the Updated Action Plan, regulated entities will also be able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol which facilitates investment by developed nations in emissions-reduction projects in developing countries. The purchase of such Emissions Reduction Credits will be restricted to 10% of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations.

Finally, a one-time credit of up to 15 million tonnes worth of emissions credits will be awarded to regulated entities for emissions reduction activities undertaken between 1992 and 2006. These credits will be both tradable and bankable.

Alberta

Alberta enacted the *Climate Change and Emissions Management Act* (the "CCEMA") on July 1, 2007, amending it through the *Climate Change and Emissions Management Amendment Act* which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach similar to the Updated Action Plan and aims for a 50% reduction from 1990 emissions relative to GDP by 2020.

Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year are subject to comply with the CCEMA. Similarly to the Updated Action Plan, the CCEMA and the associated *Specified Gas Emitters Regulation* make a distinction between "Existing Facilities" and "New Facilities". Existing Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2008 or that have completed 8 or more years of commercial operation. Existing Facilities were required to reduce their emissions intensity by March 31, 2008 by 12% from a baseline established by their average emissions intensity between 2003 and 2005. New Facilities are defined as facilities that completed their first year of commercial operation subsequent to December 31, 2008, have completed less than 8 years of commercial operation, or are designated as New Facilities in accordance with the *Specified Gas Emitters Regulation*. New Facilities are also required to reduce their emissions intensity by 12% but this target is based on the emissions intensity of the facility in its third year of commercial operation and does not apply during the first 3 years of operation of the New Facility. Unlike the Updated Action Plan, the CCEMA does not contain any provision for continuous annual improvements beyond the 12% emissions intensity required.

The CCEMA contains similar compliance mechanisms as the Updated Action Plan. Regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund (the "**Fund**") at a rate of \$15 per tonne of CO₂ equivalent. Unlike the Updated Action Plan, CCEMA contains no provisions for an increase to this contribution rate. Emissions credits can be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta. Unlike the Updated Action Plan, the CCEMA does not contemplate a linkage to external compliance mechanisms such as the Kyoto Protocol's Clean Development Mechanism.

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 initial level of the tax was set at \$10 per tonne of CO₂ equivalent and rose to \$15 per tonne of CO₂ equivalent on July 1, 2009 and \$20 per tonne of CO₂ equivalent on July 1, 2010. It is scheduled to further increase at a rate of \$5 per tonne of CO₂ equivalent on July 1 of every year until it reaches \$30 per tonne of CO₂ equivalent on July 31, 2012. 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.

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 will come into force by regulation of the Lieutenant Governor in Council. 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 greenhouse gas emissions. It is expected that greenhouse gas emissions restrictions will be applied to facilities emitting more than 25,000 tonnes of CO₂ equivalents per year, which will be required to meet established targets through a combination of emissions allowances issued by the Government of British Columbia and the purchase of emissions offsets generated through activities that result in a reduction in greenhouse gas emissions. Although more specific details of British Columbia's cap and trade plan have not yet been finalized, on January 1, 2010, new reporting regulations came into force requiring all British Columbia facilities emitting over 10,000 tonnes of CO₂ equivalents per year to begin reporting their emissions. Facilities reporting emissions greater than 25,000 tonnes of CO₂ equivalents per year are required to have their emissions reports verified by a third party.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate greenhouse gas emissions in the province. Although the MRGGA has only passed first reading in the Saskatchewan legislature and the specific details of the legislation have not yet been determined, it is expected that the MRGGA will adopt the goal of a 20% reduction in greenhouse gas emissions by 2020 and permit the use of technology fund contributions and emissions offsets in compliance, similar to both the federal and Alberta 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

An investment in the Corporation is speculative due to the nature of the Corporation's involvement in the exploration for, and the acquisition, development and production of, oil and natural gas reserves. An investor should consider carefully 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.

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, any existing reserves the Corporation may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Corporation's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Corporation will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, management of the Corporation may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Corporation.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, 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. In accordance with industry practice, the Corporation is not fully insured against all of these risks, nor are all such risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Corporation could incur significant costs. 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.

Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and continued in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating 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 may impact the performance of the global economy going forward. Although economic conditions improved towards the latter portion of 2009, as anticipated, the recovery from the recession has been slow in various jurisdictions including in Europe and the United States and has been impacted by various ongoing factors including sovereign

debt levels and high levels of unemployment which continue to impact commodity prices and to result in high volatility in the stock market.

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by numerous factors beyond its control. 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. The Corporation may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

The prices of oil and natural gas prices may be volatile and subject to fluctuation. Any 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 as a result of lower prices, which could result in reduced production of oil or 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 of these factors could result in a material decrease in the Corporation's expected net production revenue and a reduction in its oil and gas acquisition, development and exploration activities. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions, in the United States and Canada, the actions of OPEC, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and 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.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing credit and liquidity concerns. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and 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.

In addition, bank borrowings available to the Corporation may, in part, be determined by the Corporation's borrowing base. A sustained material decline in prices from historical average prices could reduce the Corporation's borrowing base, therefore reducing the bank credit available to the Corporation which could require that a portion, or all, of the Corporation's bank debt be repaid.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation makes acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as 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 business may require substantial management effort, time and resources and may divert 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 are periodically disposed of, so that 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, could be expected to 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. As a result, 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 therefore depends upon a number of factors that may be outside of the Corporation's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

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 supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Corporation could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

Competition

The petroleum industry is competitive in all its phases. The Corporation competes with numerous other organizations 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 and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources.

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. See "Industry Conditions". Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for natural gas and crude oil and increase the Corporation's costs, any 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 gas operations, the Corporation will require licenses from

various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

Environmental

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

Climate Change

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". Recently, representatives from approximately 170 countries met in Copenhagen, Denmark to attempt to negotiate a successor to the Kyoto Protocol. Pursuant to the resulting Copenhagen Accord, a non-binding political consensus rather than a binding international treaty such as the Kyoto Protocol, the Government of Canada revised its emissions reduction targets slightly. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases and require the Corporation to comply with Alberta's greenhouse gas emissions legislation contained in the *Climate Change and Emissions Management Act* and the *Specified Gas Emitters Regulation*. The Corporation may also be required to comply with the regulatory scheme for greenhouse gas emissions ultimately adopted by the federal government, which is now expected to be modified to ensure consistency with the regulatory scheme for greenhouse gas emissions adopted by the United States. The direct or indirect costs of these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The future implementation or modification of greenhouse gases regulations, whether to meet the limits required by the Kyoto Protocol, the Copenhagen Accord or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Corporation. 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 "Industry Conditions – Climate Change Regulation".

Variations in Foreign Exchange Rates and Interest Rates

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Material increases in the value of the Canadian dollar negatively impact the Corporation's production revenues. Future Canadian/United States exchange rates could accordingly impact 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, which 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. If the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. In addition, uncertain levels of near term industry activity coupled with the present global credit crisis exposes the Corporation to additional access to capital risk. 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. From time to time, the Corporation may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. 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. If the Corporation's 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 Corporation. Continued uncertainty in domestic and international credit markets could materially affect the Corporation's ability to access sufficient capital for its capital expenditures and acquisitions, and as a result, may have a material adverse effect on the Corporation's ability to execute its business strategy and on its business, financial condition, results of operations and prospects.

Issuance of Debt

From time to time the Corporation may enter into transactions to acquire assets or the 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 equity and/or 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, if commodity prices increase beyond the levels set in such agreements, the Corporation will not benefit from such increases and the Corporation may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, the Corporation will not benefit from the fluctuating exchange rate.

Availability of Drilling Equipment and Access

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

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Corporation's claim which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

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 herein are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

Estimates 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 and 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 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 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 has not been updated and thus does not reflect changes in the Corporation's reserves since that date.

Insurance

The Corporation's involvement in the exploration for and development of oil and natural gas properties may result in the Corporation becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Corporation maintains insurance in accordance with industry

standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, such 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.

Geo-Political Risks

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle-East, and other areas of the world, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of the Corporation's net production revenue.

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

Dilution

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

Management of Growth

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

Expiration of Licences and Leases

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

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.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to 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.

Seasonality

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

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 impact 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 of the Corporation are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA. See "Directors and Officers – Conflicts of Interest".

Reliance on Key Personnel

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

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⁾ Alberta, Canada	Chairman of the Board since February 17, 2005	Mr. Svarich is currently the President of DevSun Ltd., a private investment company. Mr Svarich is also currently a director of Progress Energy Resources Corp., a TSX listed company.

Name and Jurisdiction of Residence	Offices Held and Time as Director	Principal Occupation During the Last Five Years
Bruce Allford ⁽²⁾ Alberta, Canada	Director since December 20, 2004	Mr. Allford is a partner with the Calgary law firm, Burnet, Duckworth & Palmer LLP.
Brian McLachlan Alberta, Canada	President, CEO 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⁾ 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⁾ Alberta, Canada	Director since December 20, 2004	Mr. Olson is a portfolio manager with EnergyX Capital Management and has held this position since October, 2001.
Gary Perron ⁽¹⁾ Alberta, Canada	Director since December 20, 2004	Mr. Perron is the Managing Director and Senior Vice President of BMO Nesbitt Burns Inc.
John A. Brussa Alberta, Canada	Director since March 11, 2008	Mr. Brussa is a partner (since 1987) of Calgary law firm, Burnet, Duckworth & Palmer LLP, specialising in taxation. Mr. Brussa is also a director of several energy and energy-related corporations and income funds.
Clark Drader Alberta, Canada	Vice President, Land since May 1, 2005	Mr. Drader has been the Vice President, Land of Yoho since May 1, 2005.
Barry Stobo 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 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.

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 December 14, 2010 the directors and executive officers of Yoho, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 6,067,288 Common Shares, or approximately 16.3% of the issued and outstanding Common Shares.

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.

John A. Brussa was a director of Imperial Metals Limited, a corporation engaged in both oil and gas and mining operations, in the year prior to that corporation implementing a plan of arrangement under the *Company Act* (British Columbia) and under the *Companies' Creditors Arrangement Act* (Canada) which resulted in the separation of its two businesses. The reorganization resulted in the creation of two public corporations, Imperial Metals Corporation and IEI Energy Inc. (subsequently renamed Rider Resources Ltd.), both of which were listed on the TSX.

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.

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, 2010, the Corporation employed 13 full-time employees. 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 37,106,630 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		Volume Traded
	High (\$)	Low (\$)	
<u>2009</u>			
December	2.36	2.00	246,369
<u>2010</u>			
January	3.05	2.36	296,618
February	3.04	2.60	242,446
March	2.95	2.42	1,481,521
April	2.66	2.02	1,722,428
May	2.50	2.00	251,317
June	2.50	2.06	274,880
July	2.73	2.01	928,230
August	2.80	2.48	966,249
September	2.90	2.45	915,283
October	2.65	2.22	436,835
November	3.25	2.50	943,531
December (to December 14)	3.39	2.85	377,754

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, 2010, nor are there any such proceedings known to be contemplated.

During the year ended September 30, 2010 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.

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

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, our Auditors, are independent of the Corporation in accordance with the auditor's rules of professional conduct of the Institute of Chartered Accountants of Alberta.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of 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, 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.

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.
750, 736 – 6th Avenue SW
Calgary, Alberta T2P 3T7

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 prepared an evaluation of the Company's reserves data as at September 30, 2010. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at September 30, 2010, 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.

We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions in the COGE Handbook.
4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended September 30, 2010, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's Board of Directors:

Independent Qualified Reserves Evaluator	Description and Preparation 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	Corporate Evaluation December 7, 2010	Canada	-	126,271	-	126,271

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
6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.
7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, December 8, 2010

(signed) "Doug R. Sutton"

Doug R. Sutton, P. Eng
Vice-President

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 which are estimates of proved reserves and probable reserves and related future net revenue as at September 30, 2010, estimated using forecast prices and costs.

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. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(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

December 8, 2010