YANGARRA RESOURCES LTD.

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2017

March 8, 2018

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ABBREVIATIONS

Abbreviations

Oil and Natural Gas Liquids		Natural Gas	
Bbl or bbl	Barrel	Mcf or mcf	thousand cubic feet
Bbls or bbls	Barrels	Mmcf	million cubic feet
Mbbl	thousand barrels	Mcf/d or mcf/d	thousand cubic feet per day
Mmbbl	million barrels	MMcf/d	million cubic feet per day
Mstb	thousand stock tank barrels	Mbtu/d	thousand British Thermal Units per day
Bbl/d or bbl/d	barrels per day	MMBTU or mmbtu	million British Thermal Units
BOPD or bopd	barrels of oil per day	Bcf or bcf	billion cubic feet
NGLs	natural gas liquids	GJ	Gigajoule

Other

BOE or boe	barrel of oil equivalent of natural gas and crude oil on the basis of 1 Bbl of crude oil for 6 Mcf of natural gas. 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.
BOE/d, boe/d or boepd	barrel of oil equivalent per day.

In this Annual Information Form, references to "dollars" and "$" are to the currency of Canada, unless otherwise indicated and M or M$ means thousands of dollars.

FORWARD-LOOKING STATEMENTS

Certain information contained in this Annual Information Form constitutes forward-looking statements and forward-looking information within the meaning of applicable securities legislation. The use of any of the words "expect", "anticipate", "continue", "estimate", "may", "will", "should", "believe", "intend", "forecast", "plans", "guidance" and similar expressions is intended to identify forward-looking statements or information.

More particularly and without limitation, this Annual Information Form and the documents incorporated by reference herein contain forward-looking statements and information relating to the following:

- the performance characteristics of the Corporation's oil, NGLs and natural gas properties;
- oil, NGLs and natural gas production levels;
- the size of the oil, NGLs and natural gas reserves;
- projections of market prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- future funds from operations;
- capital programs;
- debt levels;
- future royalty rates;
- future depletion, depreciation and accretion rates;
- treatment under governmental regulatory regimes and tax laws; and
- capital expenditure programs.

The forward-looking statements and information contained in this Annual Information Form and in the documents incorporated by reference herein are based on certain key expectations and assumptions made by the Corporation, including expectations and assumptions relating to prevailing commodity prices and exchange rates, applicable royalty rates and tax laws, future well production rates, the performance of existing wells, the success of drilling new wells, the availability of capital to undertake planned activities and the availability and cost of labour and services.

Although the Corporation believes that the expectations reflected in the forward-looking statements and information in this Annual Information Form and in the documents incorporated by reference herein are reasonable, it can give no assurance that such expectations will prove to be correct. Since forward-looking statements and information address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results may differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to the risks associated with the oil and gas industry in general, such as operational risks in development, exploration and production, delays or changes in plans with respect to exploration or development projects or capital expenditures, the uncertainty of estimates and projections relating to production rates, costs and expenses, commodity price and exchange rate fluctuations, marketing and transportation, environmental risks, competition, the ability to access sufficient capital from internal and external sources, changes in tax, royalty and environmental legislation and the risks under the heading "Risk Factors" in this Annual Information Form. Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future. Readers are cautioned that the foregoing list of factors and risks is not exhaustive.

The forward-looking statements and information contained in this Annual Information Form and in the documents incorporated by reference herein are made as of the date hereof and, unless so required by applicable law, the Corporation undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise. The forward-looking statements and information contained in this Annual Information Form and in the documents incorporated by reference herein are expressly qualified by this cautionary statement.

READER ADVISORY

On May 30, 2014 the Corporation consolidated the common shares of the Corporation (the "**Common Shares**") on a three old Common Shares for one new Common Share (3:1) basis (the "**Consolidation**"). All references to number and value of Common Shares of the Corporation in this AIF are presented on a post-Consolidation basis unless noted otherwise.

INCORPORATION AND ORGANIZATION

Yangarra Resources Ltd. (the "**Corporation**" or "**Yangarra**") was formed on May 1, 2010 as a result of an amalgamation under the *Business Corporations Act* (Alberta) ("**ABCA**") between Yangarra and its wholly owned subsidiary, Athabaska Energy Ltd. The Corporation's predecessor entity, also called Yangarra Resources Ltd., was formed on November 9, 2005 as a result of an amalgamation under the ABCA between TriOil Ltd. ("**TriOil**") and Yangarra Resources Inc. ("**Yangarra Predecessor**"). Effective on December 31, 2009, Yangarra Predecessor acquired all of the issued and outstanding shares of Athabaska Energy Ltd. ("**Athabaska**") by issuing 50,000,004 common shares in the capital of Yangarra Predecessor at a deemed price of $0.05 per share (the "**Athabaska Acquisition**").

On May 30, 2014, the Corporation filed articles of amendment to effect the Consolidation.

TriOil was incorporated under the ABCA under the name "1000863 Alberta Ltd." and changed its name to "TriOil Ltd." and amended its share capital to add first and second preferred shares on September 26, 2002. TriOil amended its articles to remove its "private company" restrictions on November 13, 2002. Effective on August 13, 2004, TriOil amalgamated with Entrada Energy Inc. and continued to operate under the name "TriOil Ltd.".

Yangarra Predecessor was incorporated under the ABCA under the name "324220 Alberta Ltd" and changed its name to "Ayrex Resources Ltd" on August 20, 1985. Yangarra Predecessor consolidated its share capital on a four for one (4:1) basis on May 6, 2003, and changed its name to "Yangarra Resources Inc." on June 16, 2003. Yangarra Predecessor amended and registered its restated articles to include an unlimited number of common shares and preferred shares on April 30, 2004.

The Corporation's head office and registered office is located at Suite 1530, 715 - 5th Avenue S.W., Calgary, Alberta, T2P 2X6.

The Corporation has one wholly-owned subsidiary, "Yangarra Resources Corp." incorporated under the ABCA.

BUSINESS OF THE CORPORATION

Three Year History

On May 21, 2015 the Corporation closed a "bought deal" financing, completed by way of a short form prospectus, for the sale of 3,333,500 Common Shares at a price of $1.80 per share, 1,010,500 Common Shares (the "**CDE FT Shares**") issued on a "flow through" basis in respect of "Canadian development expenses" within the meaning of the Income Tax Act (Canada) at a price of $1.98 per share and 5,582,000 Common Shares (the "**CEE FT Shares**") issued on a "flow through" basis in respect of "Canadian exploration expenses" within the meaning of the Income Tax Act (Canada) at a price of $2.15 per share, for aggregate gross proceeds of approximately $20 million (the "**Offering**") (the "**May 2015 Financing**").

On May 25, 2016 the Company closed a "bought deal" financing, completed by way of a short form prospectus. 11,500,000 common shares were issued at a price of $1.00 per common share for gross proceeds of $11,500,000 (the "**May 2016 Financing**").

No significant changes are anticipated in the company's business during the current financial year.

Significant Acquisitions

On January 1, 2016, Yangarra closed the acquisition of certain strategic light oil assets in Yangarra's Central Alberta core area. The property acquisition was accounted for as a business combination under IFRS 3. The acquisition included a cash component, forgiveness of accounts receivable balances and the settlement of a lawsuit between the two parties. The fair value of the petroleum and natural gas properties acquired was determined using the total proved ("**1P**") value as at January 1, 2016, discounted at 10%, prepared by an independent reserve evaluator.

Net Assets Acquired		
Petroleum and natural gas properties	$	**22,323,000**
Decommissioning liability		**(693,818)**
Deferred tax liability		**(4,838,802)**
	$	**16,790,380**
Consideration		
Cash	$	**1,400,000**
Working capital		**2,307,693**
Gain on settlement of lawsuit		**13,082,687**
	$	**16,790,380**

DESCRIPTION OF THE BUSINESS

General

Yangarra is a growth oriented, exploration focused oil and natural gas company. The Corporation is involved in the production, exploration and development of resource properties in Central Alberta with a minor gas property in Medicine Hat. For the year ended December 31, 2017, Yangarra's oil and gas assets produced 5,740 boe/d of oil, natural gas and NGLs (compared to 2,956 boe/d of oil, natural gas and NGLs for the year ended December 31, 2016). As at December 31, 2017, Yangarra owned approximately 43,859 gross (36,278 net) acres of undeveloped land. See "Statement of Reserves Data and Other Oil and Gas Information" in this Annual Information Form.

Strategy

Yangarra plans to grow over the next five years by drilling its extensive Cardium acreage with a longer term focus on the Duvernay. Other plays with potential include Glauconitic, Rock Creek and Viking assets in Central Alberta. Longer term development includes the Second White Specs and Duvernay plays.

Yangarra's business plan is to focus on sustainable and profitable per share growth in both cash flow from operations and net asset value. To accomplish this, the Corporation will focus on enhancing its asset base through selective land acquisitions, exploratory drilling and development drilling.

The Corporation expects to internally generate exploration and development opportunities possessing medium risk and multiple prospective productive zone potential with a prudent exposure to higher risk/reward prospects. The Corporation intends to maintain a balance between exploration, development and exploitation drilling, combined with selective acquisition opportunities that meet the Corporation's business parameters. To achieve sustainable and profitable growth, the Corporation will control the timing and costs of its projects wherever possible. Accordingly, the Corporation will seek to become the operator of its properties to the greatest extent possible. Further, to minimize competition within its geographic areas of interest, the Corporation will, after giving consideration to its risk profile, strive to maximize its working interest ownership in its properties. While the Corporation intends to have the skills and resources necessary to achieve its objectives, participation in exploration and development in the oil and natural gas industry has a number of inherent risks. See "Risk Factors".

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

(a) risk capital required to secure or evaluate the investment opportunity;

(b) the potential return on the project, if successful;

(c) the likelihood of success; and

(d) the risked return versus cost of capital.

In general, the Corporation will use 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 profitable production and financial growth.

Price Risk Management

Prices received for production and associated operating expenses are impacted in varying degrees by factors outside management's control. These factors include, but are not limited to, the following:

(a) world market forces, including the ability of OPEC to set and maintain production levels and prices for crude oil;

(b) political conditions, including the risk of hostilities in the Middle East and other regions throughout the world;

(c) increases or decreases in crude oil quality and market differentials;

(d) availability of takeaway pipeline capacity;

(e) the impact of changes in the exchange rate between Canada and U.S. dollars on prices received by the Corporation for its crude oil and natural gas;

(f) North American market forces, most notably shifts in the balance between supply and demand for crude oil and natural gas and the implications for the price of crude oil and natural gas;

(g) global and domestic economic and weather conditions;

(h) price and availability of alternative fuels; and

(i) the effect of energy conservation measures and government regulations.

Revenue Sources

For the year ended December 31, 2017, 84% of the revenue from Yangarra's properties before royalties was derived from oil and NGLs and 16% was derived from natural gas (compared to 72% of the revenue being derived from oil and NGLs and 28% being derived from natural gas for the year ended December 31, 2016). Production is sold to marketers at delivery points in or close to the producing field.

Need to Replace and Grow Reserves

The future oil and natural gas production of the Corporation and, therefore, future cash flows, are highly dependent upon ongoing success in exploring on the Corporation's current and future undeveloped land base, exploiting the current producing properties and acquiring or discovering additional reserves. Without reserve additions through exploration, acquisition or development activities, reserves and production will decline over time as reserves are depleted.

The business of discovering, developing, or acquiring reserves is capital intensive. To the extent cash flows from the Corporation's operating activities are insufficient and external sources of capital become limited or unavailable, the ability for the Corporation to make the necessary capital investments to maintain and expand its oil and natural gas reserves may be impaired. There can be no assurance that the Corporation will be able to find and develop or acquire additional reserves to replace and grow production at acceptable costs.

Competition

There is strong competition relating to all aspects of the oil and natural gas industry. The Corporation will actively compete for capital, skilled personnel, undeveloped land, reserves acquisitions, access to drilling rigs, service rigs and other equipment, access to processing facilities and pipeline and refining capacity, and in all other aspects of its operations with a substantial number of other organizations, many of which may have greater technical and financial resources than the Corporation. Some of those organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a world-wide basis and as such have greater and more diverse resources on which to draw.

Personnel

As at December 31, 2017, Yangarra had 29 employees (14 head office & 15 field). As at the date hereof, Yangarra has 31 employees (14 head office & 17 field).

Bankruptcy and Reorganization

On October 7, 2009, the Corporation filed the Restructure Proposal with its creditors to restructure under Part III Division I of the *Bankruptcy and Insolvency Act* (Canada). On December 31, 2009, the Corporation completed the Athabaska Acquisition and on May 1, 2010, the Corporation amalgamated with its wholly-owned subsidiary, Athabaska under the name "Yangarra Resources Ltd.".

RISK FACTORS

The holding of securities in the Corporation should be considered highly speculative due to the nature of the Corporation's business and the present stage of its development. The following is a summary of certain risk factors relating to the activities of the Corporation and the ownership of the Corporation's securities which should be carefully considered before making an investment decision relating to the Corporation's securities.

Weakness in the Oil and Gas Industry

Recent market events and conditions, including global excess oil and natural gas supply, recent actions taken by the Organization of the Petroleum Exporting Countries ("**OPEC**"), slowing growth in China and other emerging economies, market volatility and disruptions in Asia, and sovereign debt levels in various countries, have caused significant decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry. These difficulties have been exacerbated in Canada by the recent changes in government at a federal level and, in case of Alberta, the provincial level and the resultant uncertainty surrounding regulatory, tax and royalty changes that may be implemented by the new governments. In addition, the inability to get the necessary approvals to build pipelines and other facilities to provide better access to markets for the oil and gas industry in western Canada has led to additional uncertainty and reduced confidence in the oil and gas industry in western Canada. Lower commodity prices may also affect the volume and value of the Corporation's reserves especially as certain reserves become uneconomic. In addition, lower commodity prices have reduced, and are anticipated to continue to reduce the Corporation's cash flow which could result in a reduced capital expenditure budget. As a result, the Corporation may not be able to replace its production with additional reserves and both the Corporation's production and reserves could be reduced on a year over year basis. Any decrease in value of the Corporation's reserves may reduce the borrowing base under the Credit Facilities, which, depending on the level of the Corporation's indebtedness, could result in the Corporation having to repay a portion of its indebtedness. Given the current market conditions and the lack of confidence in the Canadian oil and gas industry, the Corporation may have difficulty raising additional funds in the future or if it is able to do it may be on unfavourable and highly dilutive terms.

Credit Facilities

The amount authorized under the Corporation's Syndicated Credit Agreement is dependent on the borrowing base determined by its lenders. The lenders under the Amended and Restated Credit Agreement use the Corporation's reserves, commodity prices, and other factors, to periodically determine the Corporation's borrowing base. There remains a substantial amount of uncertainty with commodity prices. Further reductions in commodity prices could result in a reduction to the Corporation's borrowing base, reducing the funds available to the Corporation under the Credit Facilities. This could result in the requirement to repay a portion, or all, of the Corporation's indebtedness.

Volatility of Oil and Gas Prices and Markets

The Corporation's financial performance and condition are substantially dependent on the prevailing prices of oil and natural gas which are unstable and subject to fluctuation. Fluctuations in oil or natural gas prices could have an adverse effect on the Corporation's operations and financial condition and the value and amount of its reserves. Prices for crude oil fluctuate in response to global supply of and demand for oil, market performance and uncertainty and a variety of other factors which are outside the control of the Corporation including, but not limited, to the world economy and OPEC's ability to adjust supply to world demand, government regulation, political stability and the availability of alternative fuel sources. Natural gas prices are influenced primarily by factors within North America, including North American supply and demand, economic performance, weather conditions and availability and pricing of alternative fuel sources. In addition, the marketability of the production depends upon the availability and capacity of gathering systems and pipelines, the effect of federal and provincial regulation on such production and general economic conditions. All of these factors are beyond the control of the Corporation.

Decreases in oil and natural gas prices typically result in a reduction of the Corporation's net production revenue and may change the economics of producing from some wells, which could result in a reduction in the volume of the Corporation's reserves. Any substantial declines in the prices of crude oil or natural gas could also result in delay or cancellation of existing or future drilling, development or construction programs or the curtailment of production. All of these factors could result in a material decrease in the Corporation's net production revenue, cash flows and profitability and have a material adverse effect on the Corporation's operations, financial condition, proved reserves and the level of expenditures for the development of its oil and natural gas reserves, causing a reduction in its oil and gas acquisition and development activities. In addition, bank borrowings available to the Corporation will in part be determined by the Corporation's borrowing base. A sustained material decline in prices from historical average prices could further reduce such borrowing base, therefore reducing the bank credit available and could require that a portion of its bank debt be repaid.

From time to time the Corporation has and may in the future 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.

Additional Funding Requirements

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

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

Development of Additional Reserves

The Corporation's future success is dependent upon its ability to explore, develop or acquire additional oil and natural gas reserves that are economically recoverable at attractive acquisition prices. Except to the extent that the Corporation conducts successful activities or acquires properties containing proved reserves, or both, the proved reserves and production will generally decline as reserves are produced. If prevailing oil and natural gas prices were to increase significantly, the Corporation's costs to add reserves could be expected to increase. The drilling of oil and natural gas wells involves a high degree of risk, especially the risk of a dry hole or of a well that is not sufficiently productive to provide an economic return on the capital expended to drill the well.

Exploitation and development risks are due to the uncertain results of searching for and producing oil and natural gas using imperfect scientific methods. These risks are mitigated by using highly skilled staff, focusing exploitation efforts in areas in which the Corporation has existing knowledge and expertise or access to such expertise, using up-to-date technology to enhance methods and controlling costs to maximize returns. Advanced oil and natural gas related technologies such as three dimensional seismography, reservoir simulation studies and horizontal drilling may, where appropriate, be used by the Corporation to improve its ability to find, develop and produce oil and natural gas.

Title

Although satisfactory title reviews of the Corporation's properties are conducted in accordance with industry standards, those title reviews do not guarantee or certify that a defect in the chain of title may not arise to defeat the claim of the Corporation to a property.

Environmental Concerns

The operation of oil and natural gas wells involves a number of natural hazards which may result in blowouts, environmental damage or other unexpected or dangerous conditions resulting in liability to the Corporation and possibly liability to third parties. Companies operating in the oil and natural gas industry are subject to extensive environmental regulation which provides for restrictions and prohibitions on releases or emissions of various substances produced in association with certain oil and natural gas industry operations. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such legislation may result in fines or the issuance of clean-up orders. See "Information Concerning the Oil and Natural Gas Industry – Environmental Regulation". The Corporation will make reasonable provision for well abandonment and reclamation where appropriate; however, there can be no assurance that such provision will be sufficient to satisfy all such obligations. No sinking fund or reserve will be established for the purpose of site reclamation or abandonment costs.

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 controls and regulations may be amended from time to time. See "Information Concerning the Oil and Natural Gas Industry". Governments may regulate or intervene with respect to prices, 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.

Climate Change

GHG emission regulations in Canada and the US are evolving, but as these regulations are established they are likely to have a significant impact on organizations involved in the oil sands regions, including Yangarra. It is difficult to assess the overall impact these regulations will have on Yangarra at this time but it could result in increased costs to comply, delays in having projects approved and potentially a reduction in demand for oil from these regions, all of which could have a material negative impact on our business.

The direct and indirect costs of the various GHG regulations, existing and proposed, may adversely affect our business, operations and financial results. Equipment that meets future emission standards may not be available on an economic basis and other compliance methods to reduce our emissions or emissions intensity to future required levels may significantly increase operating costs or reduce the output of the projects. Offset, performance or fund credits may not be available for acquisition or may not be available on an economic basis. Any failure to meet emission reduction compliance obligations may materially adversely affect Yangarra's business and result in fines, penalties and the suspension of operations. There is also a risk that one or more levels of government could impose additional emissions or emissions intensity reduction requirements or taxes on emissions created by Yangarra or by consumers of Yangarra's products. The imposition of such measures might negatively affect

Yangarra’s costs and prices for Yangarra's products and have an adverse effect on earnings and results of operations.

Future federal legislation, including potential international requirements enacted under Canadian law, as well as provincial emissions reduction requirements, may require the reduction of GHG or other industrial air emissions, or emissions intensity, from Yangarra’s operations and facilities. Mandatory emissions reduction requirements may result in increased operating costs and capital expenditures for oil and natural gas producers. The Company is unable to predict the impact of emissions reduction legislation on the Company and it is possible that such legislation may have a material adverse effect on its business, financial condition, results of operations and cash flows.

Reserves Estimates

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. 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 consultants have used both constant and forecast price and cost estimates in calculating reserves quantities for the Corporation's reserves. 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 therefrom will vary from the estimates contained in the applicable engineering reports. The reserves reports are based in part on the assumed success of activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in the applicable engineering reports will be reduced to the extent that such activities do not achieve the level of success assumed in the engineering reports.

Purchase of Reserves

Acquisitions of resource issuers and resource assets by the Corporation will be based on engineering and economic assessments made by management and reviewed by independent engineers. These assessments include a series of assumptions regarding such factors as recoverability and marketability of oil and natural gas, future prices of oil and natural gas and operating costs, future capital expenditures and royalties and other governmental levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the Corporation. In particular, changes in the prices of and markets for oil and natural gas from those anticipated at the time of making such assessments will affect the value of the Corporation's securities. In addition, all such assessments involve a measure of geological and engineering uncertainty which could result in lower production and reserves than anticipated.

Depletion of Reserves

The Corporation's future oil and natural gas reserves and production, and therefore its cash flows, will be highly dependent on the Corporation's success in exploiting its reserve base and acquiring additional reserves. Without reserve additions through acquisition or development activities, the Corporation's reserves and production will decline over time as reserves are exploited, and from time to time production declines can be severe under certain conditions.

To the extent that external sources of capital, including the issuance of additional Common Shares, become limited or unavailable, the Corporation's ability to make the necessary capital investments to maintain or expand its oil and natural gas reserves will be impaired.

There can be no assurance that the Corporation will be successful in developing or acquiring additional reserves on terms that meet the Corporation's investment objectives.

Foreign Exchange

Operating costs incurred by the Corporation are generally paid in Canadian dollars. World oil 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 that may fluctuate over time. A material increase in the value of the Canadian dollar may negatively impact the Corporation's net production revenue. To the extent that the Corporation has engaged or will in the future engage in risk management activities related to commodity prices and foreign exchange rates, through entry into oil and natural gas price hedges and forward foreign exchange contracts or otherwise, the Corporation will be subject to unfavourable price changes and credit risks associated with the counter parties with which it contracts.

Potential Conflicts of Interest

Some of the directors of the Corporation are also directors of other oil and natural gas companies, which may from time to time be in competition with the Corporation for working interest partners, property acquisitions, or other limited resources. Where required by law, appropriate disclosure of such conflicts will be made by the applicable directors. In particular, the Corporation follows the provisions of the ABCA. These provisions state that in the event that a director has an interest in a contract or proposed contract or agreement, such director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise permitted by the ABCA.

Competition

The oil and natural gas industry is intensely competitive and the Corporation will compete for joint venture partners, capital, reserves acquisitions and skilled industry personnel with a substantial number of other companies which have greater resources. Many such companies not only explore for and produce oil and natural gas, but also carry on refining operations and market petroleum and other products on a worldwide basis and as such have greater and more diverse resources upon which to draw. There is also competition between the oil industry and other industries with respect to the supply of energy and fuel to industrial, commercial and individual customers.

Operating Risks

The oil and natural gas business involves a variety of operating risks, including the risk of fire, explosions, blowouts and encountering formations with abnormal pressure and oil spills, the occurrence of any of which could result in substantial losses to the Corporation. The Corporation will maintain insurance against some, but not all, of these risks, in amounts which meet or exceed standard industry practice. There can be no assurance that any insurance will continue to be available at premium levels that justify its purchase or whether insurance will be available at all.

Continuing production from the Corporation's properties, and to some extent the marketing of production therefrom, are dependent upon the ability of the operator of such properties. To the extent that the operator of a property fails to perform these functions properly, revenue may be reduced. Payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues if the operator becomes insolvent or experiences cash flow problems.

Changes in Legislation

There can be no assurance that income tax laws, other laws or government incentive programs relating to the oil and gas industry, will not be changed in a manner which will adversely affect the Corporation. There can be no assurance that tax authorities having jurisdiction will agree with how the Corporation calculates its income for tax purposes or that such tax authorities will not change their administrative practices to the detriment of the Corporation.

Enforcement of Operating Agreements

Operations of the wells located on properties not operated by the Corporation are generally governed by operating agreements that typically require the operator to conduct operations in a good and workmanlike manner. Operating agreements generally provide, however, that the operator will have no liability to the other non-operating working interest owners for losses sustained or liabilities incurred, except such as may result from gross negligence or wilful misconduct. In addition, third-party operators are generally not fiduciaries with respect to the Corporation.

Substantial Capital Requirements

The Corporation anticipates that it will make 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, the Corporation may have limited ability to expend the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. Moreover, future activities may require the Corporation to alter its capitalization significantly, including transactions involving the issuance of securities, which may be dilutive. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's financial condition, results of operations or 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 available on terms acceptable to the Corporation.

Issuance of Debt

From time to time the Corporation may enter into transactions to acquire assets or the shares of other corporations. These transactions may be financed partially or wholly with debt, which may increase the Corporation's debt levels above industry standards. 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 in the future on a timely basis to take advantage of business opportunities that may arise.

Insurance

The Corporation's involvement in the exploration for and development of oil and gas properties may result in the Corporation becoming subject to liability for pollution, blow-outs, property damage, personal injury or other hazards. Although the Corporation has obtained insurance in accordance with industry standards to address such risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not, in all circumstances be 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 such 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, could have a material adverse effect on the Corporation's financial position, results of operations or prospects.

Reliance on Operators and Key Employees

To the extent the Corporation is not the operator of its oil and gas properties, the Corporation will be dependent on such operators for the timing of activities related to such properties and will largely be unable to direct or control the activities of the operators. In addition, the success of the Corporation will be largely dependent upon the performance of its management and key employees. The Corporation does not have any key man insurance policies, and therefore there is a risk that the death or departure of any member of management or any key employee could have a material adverse effect on the Corporation.

Delays in Business Operations

In addition to the usual delays in payments by purchasers of oil and natural gas to the Corporation or to the operators, and the delays by operators in remitting payment to the Corporation, payments between these parties may be delayed due to restrictions imposed by lenders, accounting delays, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, adjustment for prior periods, or recovery by the operator of expenses incurred in the operation of the properties. Any of these delays could reduce the amount of cash flow available for the business of the Corporation in a given period and expose the Corporation to additional third party credit risks.

Permits and Licences

The operations of the Corporation may require licences and permits from various governmental authorities. There can be no assurance that the issuer will be able to obtain all necessary licences and permits that may be required to carry out exploration and development at its projects.

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 the Corporation's assets, however, if a claim arose and was successful, it could have an adverse effect on the Corporation and its operations.

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 potential declines in production of oil and gas of the Corporation.

Income Taxes

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

Borrowing

The Corporation's lenders have been provided with security over substantially all of the assets of the Corporation. If the Corporation becomes unable to pay its debt service charges or otherwise commits an event of default, such as bankruptcy, these lenders may foreclose on or sell the Corporation's properties. The proceeds of any such sale would be applied to satisfy amounts owed to the Corporation's lenders and other creditors and only the remainder, if any, would be available to the Corporation.

Acquisition Risk

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

Additionally, the oil and gas property acquisition business is highly competitive, and is populated with many companies, large and small, with the capital and expertise to evaluate, purchase, and exploit producing and non-producing opportunities. Even with capital and experience, the industry risks of drilling dry holes and cost overruns are significant. Environmental compliance is an increasingly complex and costly burden to entry for many new exploration areas, and often times, and even if permits are obtained, they are sufficiently restrictive that a property cannot be explored to its full potential. The Corporation may not be able to locate acquisition opportunities, or finance those that the Corporation can. The Corporation offer no assurance that its entry into this business activity will be successful.

Third Party Credit Risk

The Corporation is or 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 could have a material adverse effect on the Corporation and its cash flow from operations.

STATEMENT OF RESERVES DATA AND OTHER GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated and was prepared on February 21, 2018. The effective date of the Statement is December 31, 2017. All currency values are in Canadian dollars (unless otherwise specified).

The tables below summarize the Corporation's crude oil, NGLs and natural gas reserves and the present value of future net cash flows associated with such reserves, as December 31, 2017, as evaluated and prepared by Deloitte LLP ("**Deloitte**") independent petroleum engineers of Calgary, Alberta in the report dated February 21, 2018, based on forecasted price assumptions (the "**2017 Reserves Report**"). The 2017 Reserves Report has been prepared in accordance with the standards in the COGE Handbook and the reserves definitions set out by the Canadian Securities Administrators in National Instrument 51-101 and the COGE Handbook. The tables summarize the data contained in the 2017 Reserves Report and, as a result, may contain slightly different numbers than the 2017 Reserves Report due to rounding. All future cash flows are stated prior to provision for indirect costs and after deduction of royalties, estimated future capital expenditures and well abandonment costs. It should not be assumed that the present value of estimated future cash flows shown below is representative of the fair market value of the reserves. There is no assurance that such price and cost assumptions will be attained and variances could be material. The Corporation's crude oil, NGLs and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, NGLs and natural gas reserves may be greater than or less than the estimates provided. In the various reserves related tables included herein, columns may not add due to rounding.

The Corporation is required to pay royalties to the Crown or other royalty owners and receives royalties from various working interest parties for commodities produced. Crown royalty payments are subject to change and any changes may have an adverse impact on the profitability of a project.

Attached as Schedule "A" to this Annual Information Form is the report on reserves data of Deloitte and attached as Schedule "B" to this Annual Information Form is the report of management and directors of the Corporation on the oil and gas reserves disclosure.

Petroleum and Natural Gas Reserves and Net Present Value

The following table summarizes Deloitte's estimates of the Corporation's oil and natural gas reserves at December 31, 2017, based on forecast price assumptions and calculated without discount.

SUMMARY OF OIL AND GAS RESERVES
BASED ON FORECAST PRICES AND COSTS
AS OF DECEMBER 31, 2017

Reserves Category	**Light and Medium Oil (Mbbl)**			**Natural Gas Liquids (Mbbl)**			**Natural Gas (MMcf)**		
	W.I. Gross	Co.Share Gross	Net	W.I. Gross	Co.Share Gross	Net	W.I. Gross	Co.Share Gross	Net
Proved Developed Producing	3,102	3,102	2,701	2,471	2,478	1,906	38,221	38,314	34,724
Proved Developed Non-Producing	171	172	160	103	105	80	2,401	2,440	2,268
Proved Undeveloped	12,826	12,829	11,110	8,514	8,562	6,982	130,284	130,960	118,794
Total Proved	**16,100**	**16,102**	**13,970**	**11,088**	**11,144**	**8,968**	**170,906**	**170,714**	**155,786**
Probable	8,863	8,866	7,328	6,454	6,504	5,061	99,199	99,919	87,667
Total Proved Plus Probable	**24,963**	**24,969**	**21,298**	**17,541**	**17,648**	**14,029**	**270,105**	**271,633**	**243,453**

The following table is a summary of net present values of future net revenues associated with such reserves at December 31, 2017, based on forecast price assumptions before and after deducting income taxes, and calculated without discount and using discount rates of 5%, 10%, 15% and 20%. Future net revenue includes estimated abandonment costs related to wells and production facilities required to produce reserves.

SUMMARY OF NET PRESENT VALUES OF
FUTURE NET REVENUE
BASED ON FORECAST PRICES AND COSTS
AS OF DECEMBER 31, 2017

	Before Income Taxes				
Reserves Category	0.0% (M$)	5.0% (M$)	10.0% (M$)	15.0% (M$)	20.0% (M$)
Proved Developed Producing	311,177	245,008	203,513	175,465	155,362
Proved Developed Non-Producing	16,842	13,309	10,993	9,381	8,202
Proved Undeveloped	1,014,758	698,030	507,455	384,233	299,927
Total Proved	**1,342,776**	**956,347**	**721,962**	**569,079**	**463,491**
Probable	1,028,655	525,409	304,626	192,675	129,409
Total Proved Plus Probable	**2,371,432**	**1,481,756**	**1,026,588**	**761,754**	**592,900**

	After Income Taxes				
Reserves Category	0.0% (M$)	5.0% (M$)	10.0% (M$)	15.0% (M$)	20.0% (M$)
Proved Developed Producing	287,054	230,518	194,291	169,320	151,111
Proved Developed Non-Producing	12,295	9,950	8,430	7,375	6,601
Proved Undeveloped	740,925	499,543	354,337	260,668	196,849
Total Proved	**1,040,274**	**740,011**	**557,058**	**437,362**	**354,562**
Probable	751,148	379,668	216,560	134,015	87,606
Total Proved Plus Probable	**1,791,421**	**1,119,679**	**773,617**	**571,378**	**442,168**

The following table sets forth elements of future net revenue attributed to Proved Reserves and Proved Plus Probable Reserves of the Corporation as of December 31, 2017, based on forecast price assumptions and calculated without discount.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
BASED ON FORECAST PRICES AND COSTS
AS OF DECEMBER 31, 2017

Reserves Category	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Investment Costs (M$)	Well Abandonment Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Future Income Taxes (M$)	Future Net Revenue After Income Taxes (M$)
Proved Developed Producing	497,782	67,738	109,244	-	9,623	311,177	24,122	287,054
Proved Developed Non-Producing	27,081	2,724	6,241	1,265	9	16,842	4,548	12,295
Proved Undeveloped	2,012,525	250,374	349,055	389,650	8,688	1,014,758	273,833	740,925
Total Proved	**2,537,387**	**320,836**	**464,540**	**390,915**	**18,320**	**1,342,776**	**302,503**	**1,040,274**
Probable	1,824,019	280,323	346,506	161,543	6,992	1,028,655	277,508	751,148
Proved Plus Probable	**4,361,406**	**601,159**	**811,046**	**552,458**	**25,312**	**2,371,432**	**580,011**	**1,791,421**

The following table sets forth the net present value of future net revenues by production group attributed to Proved and Proved plus Probable Reserves of the Corporation as of December 31, 2017, based on forecast price assumptions.

NET PRESENT VALUES OF FUTURE NET REVENUE
BY PRODUCTION GROUP
BASED ON FORECAST PRICES AND COSTS
AS OF DECEMBER 31, 2017

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) (M$)	Net Reserves Unit Value Before Income Taxes (Discounted at 10%/Year)
Proved	Associated and Non-Associated Gas (including by-products)	30,273	$2.17/mcf
	Shale Gas	18,966	$3.21/mcf
	Light and Medium Oil (including solution gas and by-products)	672,723	$49.01/bbl
	TOTAL	**721,962**	$ 42.38/boe
Proved Plus Probable	Associated and Non-Associated Gas (including by-products)	55,905	$1.88/mcf
	Shale Gas	38,312	$3.04/mcf
	Associated and Non-Associated Gas (including by-products)	932,371	$44.52/bbl
	TOTAL	**1,026,588**	$ 36.66/boe

Definitions

"**W.I. Gross**" reserves are the Corporation's working interest (operating or non-operating) share before deducting royalty obligations and without including any royalty interests of the Corporation.
"**Co. Share Gross**" reserves are the Corporation's working interest (operating or non-operating) share and before deducting royalty obligations but including any royalty interests of the Corporation.
"**Net**" reserves are the Corporation's working interest (operating or non-operating) share after deduction of royalty obligations plus any royalty interests of the Corporation.
"**Reserves**" are the estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on: the analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are further classified according with the level of certainty associated with the estimates and may be sub-classified based on development and production status.
"**Production**" is the cumulative quantity of petroleum that has been recovered at a given date.
"**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. At least 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves is the targeted level of certainty.
"**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. At least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probably reserves is the targeted level of certainty.
"**Developed Reserves**" are those Reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the Reserves on production. The developed category may be subdivided into producing and non-producing.
"**Developed Producing Reserves**" are those Reserves that are expected to be recovered from completion intervals open at the time of the estimate. These Reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
"**Developed Non-Producing Reserves**" are those Reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.
"**Undeveloped Reserves**" are those Reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the Reserves classification (proved, probable) to which they are assigned.

Pricing Assumptions

Forecast Prices Used in Estimates

The forecast price and market forecasts prepared by Deloitte are based on information available from numerous government agencies, industry publication, oil refineries, natural gas marketers, and industry trends. The prices are Deloitte's best estimate of how the future will look, based on the many uncertainties that exist in both the domestic Canadian and international petroleum industries. Deloitte considers the current monthly trends, the actual and trends for the year to date, and the prior year actual in determining the forecast. The crude oil and natural gas forecasts are based on yearly variable factors weighted to higher percent in current data and reflecting a higher percent to the prior year historical. These forecasts are Deloitte's interpretation of current available information and while they are considered reasonable, changing market conditions or additional information may require alteration from the indicated effective date.

Inflation forecasts and exchange rates, an integral part of the forecast, have also been considered.

	Price Inflation Rate	Cost Inflation Rate	Cdn to US Exchange Rate
2017	1.6%	1.6%	$0.771
2018	0.0%	0.0%	$0.780
2019	2.0%	2.0%	$0.800
2020	2.0%	2.0%	$0.825
2021	2.0%	2.0%	$0.850
2022 beyond	2.0%	2.0%	$0.850

Oil, NGL, and natural gas base case prices, utilized by Deloitte in the Deloitte Reserve Report were as follows:

Price Forecast Used in Estimates

	Oil			Natural Gas		Natural Gas Liquids		
Year	WTI Cushing (Oklahoma)	Edmonton City Gate 40° API	Bow River 25° API Hardisty	Alberta Reference – Gas Prices	Alberta AECO – Gas Prices	Pentanes + Condensate Edmonton	Butanes Edmonton	Propane Edmonton
	($US/bbl)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/mcf)	($Cdn/mcf)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/bbl)
Historical								
2010	$79.40	$77.80	$68.18	$3.76	$4.01	$84.02	$68.79	$45.19
2011	$94.88	$95.54	$78.42	$3.46	$3.63	$105.24	$86.98	$52.41
2012	$94.11	$86.57	$74.41	$2.25	$2.39	$99.67	$75.47	$30.80
2013	$97.91	$93.36	$76.29	$2.98	$3.17	$103.52	$77.44	$38.54
2014	$93.26	$94.00	$81.49	$4.22	$4.50	$101.47	$59.43	$42.93
2015	$48.69	$57.00	$45.23	$2.56	$2.72	$55.15	$33.70	$5.35
2016	$42.98	$52.24	$39.13	$1.96	$2.20	$52.21	$30.75	$8.23
2017	$50.84	$62.11	$51.17	$2.19	$2.16	$62.85	$40.96	$27.56
Forecast								
2018	$55.00	$65.40	$55.40	$2.25	$2.00	$68.65	$42.50	$39.25
2019	$58.65	$68.25	$55.00	$2.55	$2.30	$71.65	$44.35	$37.55
2020	$62.40	$70.65	$57.10	$3.00	$2.75	$74.20	$45.95	$35.30
2021	$69.00	$76.15	$62.35	$3.25	$2.95	$79.95	$49.50	$34.30
2022	$75.75	$84.05	$70.00	$3.45	$3.10	$88.25	$54.60	$34.95
2023	$77.30	$85.75	$71.40	$3.70	$3.35	$90.05	$55.70	$35.65

Notes:

- All prices are in Canadian dollars except WTI and NYMEX which are in U.S. dollars.
- Edmonton City Gate prices based on light sweet crude posted at major Canadian refineries (40 Deg. API <0.5% Sulphur).
- Natural Gas Liquid prices are forecasted at Edmonton therefore an additional transportation cost must be included to plant gate sales point.
- 1 Mcf is equivalent to 1 mmbtu.
- Alberta gas prices, except AECO, include an average cost of service to the plant gate.

Weighted average historical prices realized by Yangarra for the year ended December 31, 2017 before transportation were $2.25/Mcf for natural gas, $33.74/Bbl for NGLs and $64.23/Bbl for oil.

Reconciliations of Changes in Reserves

The following table sets out a reconciliation of the changes in the Corporation's reserves as at December 31, 2017 against such reserves at December 31, 2016 based on forecast prices and cost assumptions:

	Light and Medium Oil			**Natural Gas Liquids**		
	Gross Proved	Gross Probable	Gross Proved Plus Probable	Gross Proved	Gross Probable	Gross Proved Plus Probable
	(Mstb)	(Mstb)	(Mstb)	(Mstb)	(Mstb)	(Mstb)
Opening Balance	**10,003.5**	**6,120.3**	**16,123.8**	**7,030.9**	**4,830.1**	**11,861.0**
Production	-786.2	0.0	-786.2	-361.8	0.0	-361.8
Technical Revisions	-75.4	-27.4	-102.9	80.0	47.7	127.6
Extensions & Improved Recovery	6,925.3	2,769.0	9,694.3	4,303.3	1,551.6	5,854.9
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0
Acquisitions	19.9	16.0	36.0	35.4	23.6	59.0
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	12.7	-14.7	-2.0	0.1	0.6	0.7
Infill Drilling	0.0	0.0	0.0	0.0	0.0	0.0
Closing Balance	**16,099.7**	**8,863.2**	**24,962.9**	**11,087.9**	**6,453.5**	**17,541.4**

	Shale Gas			Associated & Non-Associated Gas		
	Gross Proved	Gross Probable	Gross Proved Plus Probable	Gross Proved	Gross Probable	Gross Proved Plus Probable
	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)
Opening Balance	**7,228.4**	**8,042.5**	**15,270.9**	**108,011.4**	**70,179.1**	**178,190.5**
Production	-280.2	0.0	-280.2	-5,159.2	0.0	-5,159.2
Technical Revisions	-401.5	-446.3	-847.8	-6,659.9	-2,584.9	-9,244.8
Extensions & Improved Recovery	0.0	0.0	0.0	67,807.8	23,665.5	91,473.3
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0
Acquisitions	0.0	0.0	0.0	543.9	401.6	945.5
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	0.0	-0.6	-0.6	-184.8	-57.7	-242.5
Infill Drilling	0.0	0.0	0.0	0.0	0.0	0.0
Closing Balance	**6,546.7**	**7,595.6**	**14,142.3**	**164,359.2**	**91,603.6**	**255,962.8**

Timing of Initial Undeveloped Reserves Assignment

The following table sets forth the gross volumes of proved undeveloped reserves, by each product type, attributed to the Corporation's assets for the years ended December 2017, 2016, and 2015, based on forecast prices and costs.

<u>Proved Undeveloped Reserves</u>

Year	Light and Medium Oil (Mbbl)	Natural Gas (non-associated & associated) (MMcf)	Natural Gas Liquids (Mbbl)
2015	5,992	57,238	3,023
2016	8,062	87,171	5,378
2017	12,829	130,960	8,562

Proved undeveloped reserves are generally those reserves related to wells that have been tested and not yet tied-in for production or wells not yet drilled at year end that are adjacent to producing wells. In addition, such reserves may relate to planned infill drilling locations. Plans are included in the Deloitte report to develop these reserves. The future timing of these undeveloped reserves reflects an orderly operational development of the reserves considering infrastructure limitations and corporate portfolio management.

Deloitte has assigned 43,217 Mboe of proved undeveloped reserves in the 2017 Reserves Report under forecast prices and costs, together with approximately $391 million of associated undiscounted future capital expenditures. Proven undeveloped capital spending in the first two forecast years of the 2017 Reserves Report accounts for approximately $205 million or 52%, of the total forecast.

<u>Probable Undeveloped Reserves</u>

Year	Light and Medium Oil (Mbbl)	Natural Gas (non-associated & associated) (MMcf)	Natural Gas Liquids (Mbbl)
2015	4,280	53,664	2,670
2016	6,124	79,015	4,885
2017	8,866	99,919	6,504

Deloitte has assigned 32,023 Mboe of probable undeveloped reserves and has allocated future development capital of approximately $162 million to all probable undeveloped reserves with 6% scheduled for the first two years.

Significant Factors or Uncertainties Affecting Reserves Data

Probable undeveloped reserves are generally adjacent to proven undeveloped reserves, lands contiguous to production or indicated by analogy to be productive. In general, once proved and/or probable undeveloped reserves are identified, Yangarra schedules them into development plans within five years.

A number of factors that could result in delayed or cancelled development are: changing economic conditions (due to pricing, operating and capital expenditure fluctuations); changing technical conditions (for example production anomalies such as water breakthrough or accelerated depletion); multi-zone developments (for example, a prospective formation completion may be delayed until the initial completion is no longer economic); a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and surface access issues.

The estimation of reserves requires significant judgment and decisions based on available geological, geophysical, engineering and economic data. These estimates can change substantially as additional information from ongoing development activities and production performance becomes available and as economic and political conditions impact oil and gas prices and cost changes. The Corporation's estimates are based on current production forecast, prices and economic conditions.

As additional data and circumstances change, reserve estimates also change. Based on new information, reserves estimates are reviewed and revised, either downward or upward as warranted. As new geological, production and economic data is incorporated into the process of estimated reserves the accuracy of the reserve estimate improves.

The Corporation's reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond the Corporation's control.

The Corporation's oil and gas properties have no material extraordinary risks or uncertainties beyond those which are inherent of an oil and gas producing company which have been disclosed in financial statements and management's discussion and analysis as filed on SEDAR (www.sedar.com) and this Annual Information Form.

Future Development Costs

The following table sets forth development costs deducted in the estimation of the Corporation's future net revenue attributable to the reserve categories noted below:

	Total Proved Estimated Using Forecast Prices and Costs (Undiscounted) ($M)	Total Proved Plus Probable Estimated Using Forecast Prices and Costs (Undiscounted) ($M)
2018	102,000	102,100
2019	102,600	112,000
2020	92,800	95,000
2021	44,400	136,600
2022	48,800	105,800
Thereafter	300	1,000
Total for all years undiscounted	390,900	552,500

Yangarra expects that such funding of its share of future development on capital expenditure programs will be primarily obtained from internally generated cash flow and equity financings and debt facilities.

Oil and Gas Wells

The following table sets forth the number and status of wells in which the Corporation had a working interest or a royalty interest as at December 31, 2017, which are producing or which the Corporation considers to be capable of production. All wells set forth in the table are located in Alberta.

	Oil		Natural Gas	
	Gross	Net	Gross	Net
Medicine Hat, Alberta				
Producing	-	-	43	43.0
Shut-in	-	-	29	29.0
Central Alberta				
Producing	106	71.1	25	14.5
Shut-in	-	-	30	25.9

Notes:

(1) Shut-in wells means wells which are capable of producing crude oil or natural gas but which are not producing due to lack of available transportation facilities, available markets or other reasons.

(2) Gross wells are defined as the total number of wells in which the Corporation has an interest.

(3) Net wells are defined as the aggregate of the numbers obtained by multiplying each gross well by the Corporation's percentage working interest therein.

Property Overview

The following is a description of the major oil and natural gas properties, and facilities in which the Corporation had an interest as of December 31, 2017. Production volumes represent the working interest share of the Corporation before the deduction of royalties. Reserve amounts are stated, before deduction of royalties, at December 31, 2017 based on escalating cost and price assumptions, as set forth in the 2017 Reserves Report.

Central Alberta Area

Yangarra holds working interests ranging from 9% to 100% in multiple sections in this area with high potential Glauconitic (47 gross (26 net) sections), Cardium (84 gross (70 net) sections), Viking, Second White Specs (45 gross (29.0 net) sections), Rock Creek and Ellerslie zones. Not included in the preceding numbers, Yangarra entered into multiple farm-in's covering 36 gross (21 net) sections of Cardium rights.

The field is located 60 miles north west of Red Deer, near the town of Rocky Mountain House, Alberta. Yangarra has a 100% ownership in a compressor station in the Willesden Green area of Central Alberta capable of 10 Mmcf/d constructed in early 2004, an oil battery was added to this facility in 2016. Yangarra has compressor facility in the Ferrier area of Central Alberta that was built early in 2013, this compressor station is capable of 11 Mmcf/d. An oil battery and truck service facility were constructed in December 2017 just north of the town of Rocky Mountain House. All facilities process third party volumes providing the Corporation with incremental profit. Yangarra has a 100% interest in a field office with accommodation, a shop and storage.

As of December 31, 2017, 131 gross wells (85.6 net wells) are producing.

Medicine Hat Area

Yangarra holds a 100% working interest in a total of 75 sections of land located 25 miles southwest of the city of Medicine Hat, Alberta. A total of 81 wells have been drilled, re-entered, or acquired on the property and currently 43 wells are on production. A 100% owned compressor station, capable of 2 million cubic feet per day situated at 5-25-9-6W4 was built at the end of 2003. Production is from the Sunburst, Bow Island, Second White Specks, Medicine Hat, and Milk River Formations. Wells that have been assigned reserves and are capable of producing that have not been tied in, will be tied in as development of the field reaches these outlying wells or gas prices increase.

Properties with No Attributed Reserves

The following table sets out the Corporation's undeveloped land holdings as of December 31, 2017.

Location	Gross (hectares)	Net (hectares)
Alberta	17,763	14,693

At December 31, 2017, there was no material commitments associated with the Corporation's undeveloped land holdings. The Corporation has no rights to explore, develop, and exploit undeveloped land holdings that will expire within one year.

Significant Factors to Properties with No Attributed Reserves

The Corporation expects to develop the unrecognized natural gas assets in the Medicine Hat as natural gas prices improve.

Exploration and Development

In 2018, the Corporation intends to undertake a portfolio of exploration and development projects to capture and advance projects that provide opportunities utilizing multi-well pads and horizontal drilling with multi-stage fracturing technology. The Corporation's 2018 capital program is anticipated to be equivalent to operating cash flows and the existing bank facilities.

Additional Information Concerning Abandonment and Reclamation Costs

The 2017 Reserves Report includes well abandonment costs ranging at rates of $6,000-$70,000 per well, depending on the formation and depth of the well. The abandonment costs are based on average costs from the wells we abandoned during 2017. The 2017 Reserves Report does not address well site reclamation for existing wells, pipeline right-of-ways, and facility abandonment/salvage costs including potential environmental concerns.

Yangarra has 196 gross wells for which it expects to incur abandonment and restoration costs. These costs included well abandonment and surface lease reclamation. The estimated total abandonment and reclamation costs, forecast net of estimated salvage value, under the proved reserves category is $18,320,000 (undiscounted). The total proved plus probable abandonment and reclamation costs are $25,312,000 (undiscounted). 100% of such amounts were deducted as abandonment costs in estimating future net revenue of the Corporation in respect of proved and proved plus probable reserves as disclosed above. Estimated abandonment costs are included in the 2017 Reserves Report as a deduction in arriving at future net revenue.

Forecast Prices and Costs – Proved (M$)

Year	Abandonment Costs (Undiscounted)
2018	-
2019	300
2020	500
2021	500
2022	400
Thereafter	16,620
Total	18,320

Forecast Prices and Costs – Proved Plus Probable (M$)

Year	Abandonment Costs (Undiscounted)
2018	-
2019	300
2020	500
2021	400
2022	400
Thereafter	23,712
Total	25,312

Forward Contracts

As at December 31, 2017, the Corporation was committed to the following commodity price risk contracts:

<u>Oil</u>
200 bbl/d January to December 2018 in a collar with a $62.50 CDN/bbl floor and a $75.90 CDN/bbl ceiling
300 bbl/d January to June 2018 in a collar with a $62.50 CDN/bbl floor and a $76.10 CDN/bbl ceiling
300 bbl/d January 1 to December 2018 at CDN$71.60 WTI/bbl
300 bbl/d January 1 to June 2018 at CDN$75.17/bbl
300 bbl/d January 1 to June 2018 at USD$49.10/bbl
300 bbl/d January 1 to June 2018 at USD$52.15/bbl
300 bbl/d January 1 to June 2018 at USD$56.75/bbl
Sold Call on 300 bbl/d January to December 2018 at US$70.00/bbl
Sold Call on 300 bbl/d July to December 2018 at CDN$75.17/bbl
Sold Call on 500 bbl/d January to December 2019 at US$60.00/bbl
Sold Call on 200 bbl/d January to December 2019 at US$65.00/bbl

<u>Propane</u>
200 bbl/d January 1 to December 2018 at USD$32.34/bbl

Tax Horizon

Yangarra was not required to pay income tax in 2017 and based on current tax pools, projected cash flow, and projected exploration costs, the Corporation does not expect to be taxable in 2018.

Costs Incurred

For the year ended December 31, 2017, exploration and development capital expenditures were 83.5 million. The breakdown for the Corporation's capital expenditures during 2017 is presented below:

	($000's)
Land, acquisitions and lease rentals	$ 7,164,597
Drilling and completion	64,309,093
Geological and geophysical	824,759
Equipment	10,853,654
Other asset additions	319,990
Total	$ 83,472,093

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which Yangarra participated during the year ended December 31, 2017.

Exploration Wells	Gross	Net	Development Wells	Gross	Net
Light and Medium Oil	-	-	Light and Medium Oil	16	15.0
Natural Gas	-	-	Natural Gas	-	-
Service	-	-	Service	-	-
Dry	-	-	Dry	-	-
Total	-	-	Total	16	15.0

Production Estimates

The following table sets out the volume of Yangarra's production estimated for the first year reflected in the estimates of future gross revenue disclosed in the tables contained under "Disclosure of Reserves Data".

	Total Proved Reserves			Total Proved + Probable Reserves		
	Light and medium oil (bbl/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (bbl/d)	Light and medium oil (bbl/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (bbl/d)
Medicine Hat	-	373	-	-	402	-
Central Alberta	4,932	34,434	2,131	4,969	34,420	2,153

* Table includes fields that account for more than 20% of the estimated production reflected in the estimate of future net reserves.

Production History

The following tables set forth the Corporation's average daily production volume before deductions of royalties payable to others, and crude oil, NGLs and natural gas prices. Also shown are royalties, production and transportation costs, and average netbacks for the period January 1, 2017 – December 31, 2017.

Average Daily Production

Three months ended	March 31	June 30	Sept 30	Dec 31
Light and medium oil (bbl/d)	1,836	2,281	2,373	2,680
Natural gas (mcf/d)	11,019	15,587	16,142	16,782
Natural gas liquids (bbl/d)	810	827	963	1,244
Total (BOE/d)	4,483	5,705	6,025	6,721

Average Prices Received per Unit – (Excluding commodity contracts, before deduction of royalties)

Three months ended	March 31	June 30	Sept 30	Dec 31
Light and medium oil ($/bbl)	64.35	62.63	56.51	72.33
Natural gas ($/mcf)	3.09	2.89	1.60	1.77
Natural gas liquids ($/bbl)	29.96	27.85	33.39	40.29
($ / BOE)	38.75	38.53	31.87	40.71

Royalties Paid per Unit

Three months ended	March 31	June 30	Sept 30	Dec 31
Total royalties ($/BOE)	3.05	2.86	2.43	3.80

Production and Transportation Costs

Three months ended	March 31	June 30	Sept 30	Dec 31
Total costs ($/BOE)	7.93	8.98	6.86	7.46

Netbacks Received

Three months ended	March 31	June 30	Sept 30	Dec 31
Total netbacks ($/BOE)	27.56	25.76	25.53	30.39

Production Volume by Field

The following table indicates the Corporation's average daily production from its important fields for the year ended December 31, 2017:

	Light and Medium Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	BOE (BOE/d)
Medicine Hat	-	264	-	44
Central Alberta	2,295	14,630	962	5,695
Viking South	-	8	-	1

Uncertainty of Reserves Estimates

The reserve and recovery information contained in the 2017 Reserves Report is only an estimate and the actual production and ultimate reserves from the properties may be greater or less than the independent estimates of Deloitte.

There are numerous uncertainties inherent in estimating quantities of reserves and cash flows to be derived therefrom, including many factors that are beyond the control of the Corporation. The reserve and cash flow information set forth herein represent estimates only. The reserves and estimated future net cash flow from the Corporation's assets have been independently evaluated effective December 31, 2017 by Deloitte. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of oil and natural gas, operating costs and royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date the relevant evaluations were prepared and many of these assumptions are subject to change and are beyond the control of the Corporation. Actual production and cash flows will vary from these evaluations, and such variations could be material. The foregoing evaluations are based in part on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success in the evaluations.

DIRECTORS AND OFFICERS OF THE CORPORATION

The name, province and country of residence and principal occupation for the last five years of each of the directors and executive officers of the Corporation are as follows:

Name and Municipality of Residence	Office	Principal Occupation	Director Since
James G. Evaskevich Calgary, Alberta	President, Chief Executive Officer, and Director	President and Chief Executive Officer of the Corporation since December 2001.	December 19, 2001
James A. Glessing Calgary, Alberta	Chief Financial Officer	Chief Financial Officer of the Corporation since December 1, 2010. Prior thereto CFO & VP Finance of North Peace Energy (2007-2010).	N/A
Randall J. Faminow Calgary, Alberta	Vice President, Land	VP Land of the Corporation since October 18, 2011. Prior thereto VP, Land for Spry Energy Ltd (2007-2011).	N/A
Lorne D. Simpson Cochrane, Alberta	Vice President, Operations	VP Operations of the Corporation since April 11, 2013. Prior thereto Manager of Drilling and Completions for the Corporation (2012-2013), Supervisor, Drilling Operations with PetroBakken Energy Ltd. (2010-2012), Manager Drilling and Completions with Open Range (2009-2010).	N/A
Gordon A. Bowerman(1)(2)(3) Calgary, Alberta	Director	President of Cove Resources Ltd., a private oil and gas company based in Calgary, since 1987.	December 19, 2001
Robert D. Weir(1)(2)(3) Calgary, Alberta	Director	President of Weir Resource Management Ltd., a private company based in Calgary, since 1981.	November 11, 2003
Frederick (Ted) L. Morton(1)(2)(3) Calgary, Alberta	Director	Professor at the University of Calgary (1981 – present) and MLA, Foothills Rockyview (2004 – 2012).	February 24, 2014
Neil M. Mackenzie (1)(2)(3) Calgary, Alberta	Director	Vice President of Blackstone Drilling Fluids Ltd. (2010 – present), Vice President New Park Resources (1976 – 2010) and President Challenger Energy Corp. (2004 – 2007).	February 24, 2014

Notes:

(1) Member of the Audit Committee.
(2) Member of the Corporate Governance and Nominating Committee.
(3) Member of the Compensation Committee.

Each director of the Corporation shall hold office until the next annual meeting of shareholders or until their successors are duly elected or appointed pursuant to the Corporation's by-laws, unless the director's office is earlier vacated.

Shareholdings of Directors and Executive Officers

As at December 31, 2017, the directors and officers of the Corporation, as a group, beneficially owned or controlled, directly or indirectly, 9,458,488 Common Shares, representing approximately 12% of the issued and outstanding Common Shares as at that date. The directors and executive officers, as a group, also held options to purchase 5,070,017 Common Shares at December 31, 2017.

The fully diluted holdings of directors and executive officers, as a group were 14,528,505 Common Shares, or approximately 16% of the Common Shares that were outstanding on a fully diluted basis, at December 31, 2017.

Cease Trade Orders

To the knowledge of management of the Corporation, other than as disclosed herein, no director or executive officer as at the date hereof, or was within 10 years before the date hereof, a director, chief executive officer or chief financial officer of any company (including the Corporation), that (a) was subject to an order that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer, or (b) was subject to an order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer. For the purposes hereof, "order" means (a) a cease trade order, (b) an order similar to a cease trade order, or (c) an order that denied the relevant company access to any exemption under securities legislation that was in effect for a period of more than 30 consecutive days.

Bankruptcies

Other than as disclosed below, no director or executive officer of the Corporation is, as of the date hereof, or has been, within 10 years before the date hereof, a director or executive officer of any company that, while such person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal to 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.

On October 7, 2009 the Corporation filed a proposal with its creditors to restructure under Part III Division I of the *Bankruptcy and Insolvency Act* (Canada), including a plan to merge with Athabaska Energy Ltd. See "Interest of Informed Persons in Materials Transactions" below. At the time of the Restructure Proposal, the directors and officers of Yangarra consisted of James Evaskevich, Gordon Bowerman and Robert Weir.

No director or executive officer of the Corporation has, within 10 years before the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold its assets.

Penalties and Sanctions

To the knowledge of management of the Corporation, no director or executive officer or shareholder holding a sufficient number of common shares to affect materially the control of the Corporation, has been subject to any penalties or sanctions imposed by a court relating to Canadian securities legislation or by a Canadian securities regulatory authority or has entered into a settlement agreement with a Canadian securities regulatory authority, or has been subject to any other penalties or sanctions imposed by a court or regulatory body that would be likely to be considered important to a reasonable investor making an investment decision.

Conflicts of Interest

There are potential conflicts of interest to which the directors and officers of the Corporation will be subject to in connection with the operations of the Corporation. In particular, certain of the directors and officers of the Corporation are involved in managerial or director positions with other oil and natural gas companies whose operations may, from time to time, be in direct competition with those of the Corporation or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of the Corporation. In accordance with the ABCA, directors who have a material interest or any person who is a party to a material contract or a proposed material contract with the Corporation are required, subject to certain exceptions, to disclose that interest and generally abstain from voting on any resolution to approve the contract. In addition, the directors are required to act honestly and in good faith with a view to the best interests of the Corporation. Certain of the directors of the Corporation have either other employment or other business or time restrictions placed on them and accordingly, these directors of the Corporation will only be able to devote part of their time to the affairs of the Corporation.

AUDIT COMMITTEE

The purpose of the Corporation's audit committee is to provide assistance to the Board of Directors (the "**Board**") in fulfilling its legal and fiduciary obligations with respect to matters involving the accounting, auditing, financial reporting, internal control and legal compliance functions of the Corporation. It is the objective of the audit committee to maintain a free and open means of communications among the Board, the independent auditors and the senior management of the Corporation.

The full text of the audit committee's charter is attached hereto as Schedule "C" and forms part of this Annual Information Form.

Composition of the Audit Committee

The audit committee is comprised of Gordon Bowerman (Chair), Robert Weir, Frederick (Ted) Morton and Neil Mackenzie. Each of the members are independent within the meaning of section 1.4 of National Instrument 52-110 *Audit Committees* ("**NI 52-110**"). Each of the members is financially literate within the meaning of section 1.6 of NI 52-110.

Relevant Education and Experience

The following relevant education and experience of the members of the Audit Committee have been used in assessing their financial literacy and are relevant to the performance of their responsibilities as audit committee members:

Gordon Bowerman, B.A. – Mr. Bowerman has over 40 years experience in the oil and gas industry, including various experience in production, land, accounting, asset purchases and sales. Mr. Bowerman currently is the President of a private oil and gas company.

Robert Weir, P. Eng – Mr. Weir has over 30 years experience in the oil and gas industry, President of Weir Resource Management Ltd., a private company based in Calgary, since 1981.

Frederick (Ted) Morton B.A. PhD – Mr. Morton's various positions in the Alberta Government included Minister of Energy, Minister of Finance and Enterprise, and Minster of Sustainable Resources.

Neil Mackenzie –Mr. MacKenzie is or has been a director of various public companies, including Canyon Services Group Inc., and is currently a Vice President at Blackstone Drilling Fluids Ltd., an oil and gas drilling fluids company. Mr. MacKenzie held senior position in oil and gas companies from 1976-2010.

Pre-Approval Policies and Procedures

The audit committee pre-approves engagements for non-audit services provided by the external auditors or their affiliates, together with estimated fees and potential issues of independence.

Audit Committee Oversight

At no time since the commencement of the Corporation's most recently completed financial year was a recommendation of the Committee to nominate or compensate an external auditor (currently, MNP LLP, Chartered Accountants) not adopted by the Board.

Reliance on Certain Exemptions

Since the effective date of NI 52-110, the Corporation has not relied on the exemptions contained in sections 2.4 (*De Minimis Non-audit Services*), 3.2 (*Initial Public Offerings*), 3.4 (*Events Outside Control of Member*), 3.5 (*Death, Disability or Resignation of Audit Committee Member*), of NI 52-110, or an exemption, in whole or in part, granted under Part 8 of NI 52-110.

External Auditor Service Fees (By Category)

Year Ended	Audit Fees	Audit Related Fees	Tax Fees	All Other Fees
December 31, 2017	$70,000[(1)]	$nil	$nil	$nil
December 31, 2016	$126,700[(2)]	$nil	$nil	$nil

Notes:

(1) Includes $30,000 for quarterly reviews.

(2) Includes $27,000 for quarterly reviews and $61,700 for involvement in a short-form prospectus dated May 25, 2016.

DESCRIPTION OF SHARE CAPITAL

The Corporation is authorized to issue an unlimited number of Common Shares, without nominal or par value, and an unlimited number of First Preferred Shares (the "**First Preferred Shares**") and the Second Preferred Shares in the capital of the Corporation, both issuable in series (the "**Second Preferred Shares**", and together with the First Preferred Shares, the "**Preferred Shares**"). As of the date of this Annual Information Form, 81,378,490 Common Shares and nil Preferred Shares are issued and outstanding.

Common Shares

Holders of Common Shares are entitled to: (a) one vote per post-consolidated Common Share at all meetings of shareholders of the Corporation; (b) receive dividends if, as and when declared by the Board, as a class equally with the holders of the Preferred Shares, subject to prior satisfaction of all preferential rights to dividends attached to all shares of other classes ranking in priority to the Common Shares in respect of dividends; and (c) in the event of any liquidation, dissolution or winding up of the Corporation, whether voluntary or involuntary, or any other distribution of its assets for the purpose of winding up its affairs, subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all shares of other classes of shares of the Corporation ranking in priority to the Common Shares in respect of return of capital on dissolution, share rateably, together with the holders of Preferred Shares and of shares of any other class of shares of the Corporation ranking equally with the Common Shares in respect of return of capital on dissolution, in such assets of the Corporation as are available for distribution.

First Preferred Shares

Holders of First Preferred Shares shall: (a) not be entitled to receive notice of, to attend or vote at any meeting of the shareholders of the Corporation; (b) be entitled to receive dividends if, as and when declared by the Board on the First Preferred Shares as a class in preference to the holders of the Second Preferred Shares and Common Shares, and any other shares of the Corporation ranking junior to the First Preferred Shares in respect of the dividends; and (c) be entitled to, in the event of any liquidation, dissolution or winding up of the Corporation, whether voluntary or involuntary, or any other distribution of its assets for the purpose of winding up its affairs, receive in preference to the holders of the Second Preferred Shares and Common Shares, and any other shares of the Corporation ranking junior to the First Preferred Shares in respect of return of capital on dissolution, in such assets of the Corporation as are available for distribution.

Series A First Preferred Shares

The Corporation previously had a series of First Preferred Shares outstanding ("**Series A First Preferred Shares**") Holders of Series A First Preferred Shares shall: (a) not be entitled to receive notice of, to attend or vote at any meeting of the shareholders of the Corporation; (b) be entitled to receive dividends: (i) on a semi-annual basis within 30 days of the first and second fiscal-year halves of the Corporation, which can be paid in the form of cash or Common Shares at the election of the Board, with the deemed price of such Common Shares to be the Market Price (as such term is defined in the Corporate Finance Manual of the TSX Venture Exchange) of such Common Shares at the time of settlement on the First Preferred Shares; (ii) as a class in preference to the holders of the Second Preferred Shares and Common Shares, and any other shares of the Corporation ranking junior to the First Preferred Shares in respect of the dividends; and (iii) each Series A First Preferred Share shall be entitled to a cumulative dividend at the rate of 5% per annum on the stated amount of $1.00 per Series A Preferred Share (the "**Stated Amount**") of such Series A First Preferred Share; (c) be entitled to, in the event of any liquidation, dissolution or winding up of the Corporation, whether voluntary or involuntary, or any other distribution of its assets for the purpose of winding up its affairs, receive an amount equal to the Stated Amount per Series A First Preferred Share plus any declared but unpaid dividends prior to any payment or distribution to any other class of shares of the Corporation; and (d) have the option, exercisable not earlier than the date that is 18 months after the Series A Preferred Shares are issued, to force the Corporation to redeem or purchase all or any of the Series A First Preferred Shares held by such holder. In addition, the Corporation has the right to redeem the Series A First Preferred Shares at any time in cash at the price equal to the Stated Amount plus any declared but unpaid dividends.

Second Preferred Shares

Holders of Second Preferred Shares shall not be entitled to: (a) receive notice of, to attend or vote at any meeting of the shareholders of the Corporation; (b) receive dividends if, as and when declared by the Board on the First Preferred Shares as a class in preference to the holders of the Common Shares, and any other shares of the Corporation ranking junior to the First Preferred Shares in respect of the dividends, subject to prior satisfaction of all preferential rights to dividends attached to all shares of other classes ranking in priority to the Second Preferred Shares in respect of dividends; and (c) in the event of any liquidation, dissolution or winding up of the Corporation, whether voluntary or involuntary, or any other distribution of its assets for the purpose of winding up its affairs, receive in preference to the holders of the Common Shares, and any other shares of the Corporation ranking junior to the First Preferred Shares, subject to prior satisfaction of all preferential rights to dividends attached to all shares of other classes ranking in priority to the Second Preferred Shares in respect of return of capital on dissolution, in such assets of the Corporation as are available for distribution.

DIVIDENDS

The Corporation has not declared or paid any dividends on the Common Shares. Any decision to pay dividends on such shares in the future will be made by its Board on the basis of the Corporation's earnings, financial requirements and other conditions existing at such future time. It is not the current intention of the Corporation to pay any dividends on the Common Shares in the near future.

MARKET FOR SECURITIES

Trading Price and Volume

The Common Shares have been listed and posted for trading on the Toronto Stock Exchange ("**TSX**") since June 27, 2014. Prior thereto, the Common Shares were listed and posted for trading on the TSX Venture Exchange. The following table sets out the price range for, and trading volume of the Common Shares as reported by the TSX for the periods indicated:

	Trading Price		Volume Traded
	High	**Low**	**# of shares**
January 2017	$2.52	$1.86	6,002,900
February 2017	$2.82	$2.28	5,380,100
March 2017	$2.85	$2.30	7,019,200
April 2017	$2.94	$2.45	3,654,800
May 2017	$3.53	$2.48	4,887,900
June 2017	$3.48	$2.77	4,322,100
July 2017	$3.54	$3.05	2,043,600
August 2017	$3.49	$2.96	2,207,500
September 2017	$4.00	$3.13	4,624,400
October 2017	$4.11	$3.46	3,922,100
November 2017	$4.95	$3.77	5,751,600
December 2017	$5.05	$4.04	2,932,200

ESCROWED SECURITIES

No securities of the Corporation are currently escrowed.

INFORMATION CONCERNING THE OIL AND NATURAL GAS INDUSTRY

Government Regulation

The oil and natural gas industry in Canada is subject to extensive controls and regulations imposed by various levels of government, and our oil and gas operations are subject to various Canadian federal, provincial, territorial, and local laws and regulations. These laws and regulations may be changed in response to economic or political conditions, and regulate, among other things, land tenure and the exploration, development, production, handling, storage, transportation, and disposal of oil and gas, oil and gas by-products, and other substances and materials produced or used in connection with oil and gas operations.

More particularly, matters subject to current governmental regulation and/or pending legislative or regulatory changes include the licensing for drilling of wells, the method and ability to produce wells, surface usage, transportation of production from wells, conservation matters, the discharge or other release into the environment of wastes and other substances in connection with drilling and production activities (including fracture stimulation operations), bonds or other financial responsibility requirements to cover drilling contingencies and well plugging and abandonment costs, reports concerning our operations, the spacing of wells, unitization and pooling of properties, and royalties and taxation. Failure to comply with the laws and regulations in effect from time to time may result in the assessment of administrative, civil, and criminal penalties, the imposition of remedial obligations, and the issuance of injunctions that could delay, limit, or prohibit certain of our operations. The Corporation cannot predict the ultimate cost of compliance with these requirements or their effect on our operations.

Federal authorities do not regulate the price of oil and gas in export trade. Legislation exists, however, that regulates the quantities of oil and natural gas which may be removed from the provinces and exported from Canada in certain circumstances. At various times, regulatory agencies have imposed price controls and limitations on oil and gas production. In order to conserve supplies of oil and gas, these agencies may also restrict the rates of flow of oil and gas wells below actual production capacity.

Although Yangarra does not expect that these controls and regulations will affect the operations of Yangarra in a manner materially different than they would affect other oil and gas companies of similar size, the controls and regulations should be considered carefully by investors in the oil and gas industry. All current legislation is a matter of public record and Yangarra is unable to predict what additional legislation or amendments may be enacted.

Pricing and Marketing

Oil

Producers of crude oil, bitumen, and bitumen blend negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of such commodities. The price depends, in part, on product quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance, other contractual terms, and the world price of oil. Oil may be exported from Canada pursuant to export contracts with terms not exceeding one year in the case of light crude, and not exceeding two years in the case of heavy crude, provided that an order approving such export has been obtained from the NEB. Any oil exported under a contract of longer duration (to a maximum of 25 years) requires the exporter to obtain an export licence from the NEB and the issuance of such licence requires the approval of the Governor in Council. On December 18, 2015, the U.S. Congress passed and the President signed legislation into law which repealed the 40-year old ban on exports of crude oil produced in the United States. Accordingly, most exports of domestically-produced crude oil may be made without an export license. Only exports to embargoed or sanctioned countries continue to require authorization from the U.S. Department of Commerce.

Natural Gas

In Canada, the price of natural gas sold in intraprovincial, interprovincial and international trade is determined by negotiations between buyers and sellers. Such price depends, in part, on natural gas quality, prices of competing natural gas and other fuels, distance to market, access to downstream transportation, length of contract term, weather conditions, the supply/demand balance and other contractual terms. Natural gas exported from Canada is subject to regulation by the NEB and the government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the NEB and the government of Canada. Natural gas exports for a term of less than two years or for a term of two to 20 years (in quantities not exceeding 30,000 m3/day) are subject to an NEB order. Any natural gas exported under a contract of longer duration (to a maximum of 25 years) or in larger quantities requires the exporter to obtain an export licence from the NEB and the issuance of such licence requires the approval of the Governor in Council.

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

Natural Gas Liquids

The price of condensate and other natural gas liquids ("**NGLs**") sold in intraprovincial, interprovincial and international trade is determined by negotiations between buyers and sellers. Such price depends, in part, on the quality of the NGLs, prices of competing chemical stock, distance to market, access to downstream transportation, length of contract term, the supply/demand balance and other contractual terms. NGLs exported from Canada are subject to regulation by the NEB and the government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the NEB and the government of Canada. NGLs may be exported for a term of not more than one year in respect of propane and butane and not more than two years in respect of ethane – with all exports requiring an order of the NEB.

The North American Free Trade Agreement

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

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

The Trump administration has indicated an intent to renegotiate the terms of NAFTA.

Gathering and Processing Facilities and Pipeline Systems

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

The Federal Government has signaled that it plans to review the National Energy Board approval for large projects. This may cause the timeframe for project approvals for current and future applications to increase.

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

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

Transportation Capacity

Despite some recent oil pipeline capacity expansions, Canada's overall pipeline capacity and ability to access the United States Midwest and tidewater is constrained. The transportation capacity deficit is not likely to be resolved quickly given that production of heavy oil and bitumen in Canada is expected to continue to increase. As further outlined below, several pipeline projects have been proposed and are currently in the approvals stage. If the proposed projects are approved, the pipelines would help to alleviate the problems that Canada faces in accessing global markets for its oil supply. The completion of new pipelines is not guaranteed, however, as evidenced by TransCanada Corporation’s termination in October 2017 of its proposed Energy East pipeline, which was to have a capacity of 1.1 million bbls/d.

While the use of rail transportation as an alternative to pipelines has significantly increased in recent years, regulatory changes may impact the ability of producers to access markets by rail. The Regulations Amending the Transportation of Dangerous Goods Regulations (TC 117 Tank Cars) issued under the Transportation of Dangerous Goods Act, 1992, were adopted and came into force on May 20, 2015. The amended regulations will require rail tank cars to meet higher safety standards, which will be phased in over time until 2025.

Proposed Pipeline Projects

Kinder Morgan Canada's proposed expansion of its existing Trans Mountain Pipeline from Edmonton, Alberta to Burnaby, British Columbia was approved by the NEB in May, 2016, and by the federal government in November, 2016. However, the future of the project, which is expected to increase capacity by 590,000 bbls/d, is currently uncertain. In September 2017, the Federal Court of Appeal found that the government failed in its duty to protect Indigenous interests and ordered the government to renegotiate the terms under which the proposed pipeline will cross a First Nations reserve. Several other court challenges have been brought by First Nations, environmental groups and local municipalities. The recently-elected NDP government in British Columbia has also indicated its intention to block the expansion. Various court and NEB decisions on these issues are expected in 2018.

The TransCanada Corporation led Keystone XL project would add 830,000 bbls/d in pipeline capacity for Canadian crude oil to flow to the American Gulf Coast market. Despite having been previously rejected by the Obama administration, President Trump announced his administration's approval of the project on March 24, 2017. TransCanada Corporation has indicated that it expects construction of the project to commence after remaining local and state permits are issued, and for the pipeline to be in service two to three years following the commencement of construction.

Enbridge Inc.’s Line 3 proposed replacement project of its existing pipeline from Hardisty, Alberta to Wisconsin, United States was approved by the NEB in April, 2016, and by the federal government in November, 2016. The pipeline is expected to increase capacity by 370,000 bbls/d. United States regulatory approval processes are currently underway; however, the project has faced multiple delays, most recently from a Minnesota court, which found in December 2017 that Enbridge Inc.'s environmental impact statement for the project was inadequate. A final decision from Minnesota is not expected until June 2018. Enbridge Inc.'s goal is for the replacement pipeline to be in service by November 2019.

The Canadian Association of Petroleum Producers' crude oil forecast from June 2017 states that oil sands production was approximately 2.4 million bbls/d in 2016 and that production is forecast to increase to 3.7 million bbls/d by 2030. Accordingly, finding additional export capacity to deal with the increase in Canada's crude oil production is a primary concern.

The projects noted above are anticipated to help to alleviate access problems faced by large number of oil and gas companies with properties in Western Sedimentary Basin, if completed.

Land Tenure

Rights are granted to energy companies to explore for and produce oil and natural gas pursuant to leases, licenses, and permits and regulations as legislated by the respective Provincial and Federal governments. Lease terms vary in length, usually from two to five years. Other terms and conditions to maintain a mineral lease are set forth in the relevant legislation or are negotiated.

Oil produced from oil sands owned by the Province of Alberta is produced under provincial Crown oil sands leases. Two types of oil sands agreements are issued under the Oil Sands Tenure Regulation, 2010 made under the *Mines and Minerals Act*: (i) permits, issued for a five-year term, which can be converted to leases; and (ii) leases, issued for an initial 15-year term, which can be continued as to all or any portion the Minister of Energy may determine. The regulation requires that exploration or development activity be undertaken according to prescribed levels of evaluation or production. Permits may generally be converted to leases provided certain minimum levels of exploration have been achieved and all lease rentals have been timely paid. A lease may generally be continued after the initial term as to all or any portion the Minister of Energy may determine, provided certain minimum levels of exploration or production have been achieved and all lease rentals have been timely paid. The surface rights required for pipelines, upgraders and cogeneration and other facilities are generally governed by leases, easements, rights-of-way, permits or licenses granted by landowners or governmental authorities.

Jurisdictions in western Canada, including the provinces of Alberta, and Saskatchewan have legislation in place for mineral rights reversion to the Crown where formations cannot be shown to be capable of production at the end of their primary lease term. Such legislation may also include mechanisms available to energy companies to "continue" lease terms for non-productive lands, having met certain criteria as laid out in the relevant legislation.

Oil and natural gas 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.

Royalties and Incentives

General

For crude oil, natural gas and related production from Federal or Provincial government lands, the royalty regime is a significant factor in the profitability of our production. Crown royalties payable in respect of crown lands are determined by governmental regulation and are typically calculated as a percentage of the value of gross production. The value of the production and the rate of royalties payable generally depend on prescribed reference prices, well productivity, geographical location, the field discovery rate and the type of product produced.

Royalties payable on production from privately owned lands are determined by negotiations between the mineral owner and the resource owner, although production from such lands is subject to certain provincial taxes and royalties. Any such royalties (or royalty-like interests) are carved out of the working interest owner’s interest through non-public transactions and are often referred to as overriding royalties, gross overriding royalties, net profit interests or net carried interests.

From time to time, provincial governments have established incentive programs for exploration and development. Such programs often provide for royalty reductions, credits and holidays, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry.

Alberta

Alberta has adopted a new, modernized Alberta royalty framework (the "**Modernized Framework**") that applies to all wells drilled after January 1, 2017. The previous royalty framework (the "**Old Framework**") will continue to apply to wells drilled prior to January 1, 2017 for a period of ten years ending on December 31, 2026. After the expiry of this ten-year period, these older wells will become subject to the Modernized Framework.

The Modernized Framework applies to all hydrocarbons other than oil sands which will remain subject to their existing royalty regime. Royalties on production from non-oil sands wells under the Modernized Framework is determined on a “revenue-minus-costs” basis with the cost component based on a Drilling and Completion Cost Allowance formula for each well, depending on its vertical depth and horizontal length. The formula is based on the industry’s average drilling and completion costs as determined by the Alberta Energy Regulator ("**AER**") on an annual basis.

Producers pay a flat royalty rate of 5 percent of gross revenue from each well that is subject to the Modernized Framework until the well reaches payout. Payout for a well is the point at which cumulative gross revenues from the well equals the Drilling and Completion Cost Allowance for the well set by the AER. After payout, producers pay an increased post-payout royalty on revenues determined by reference to the then current commodity prices of the various hydrocarbons. Similar to the Old Framework, the post-payout royalty rate under the Modernized Framework varies with commodity prices. Once production in a mature well drops below a threshold level where the rate of production is too low to sustain the full royalty burden, its royalty rate is adjusted downward as the mature well's production declines.

As the Modernized Framework uses deemed drilling and completion costs in calculating the royalty and not the actual drilling and completion costs incurred by a producer, low cost producers benefit if their well costs are lower than the Drilling and Completion Cost Allowance and, accordingly, they continue to pay the lower 5% royalty rate for a period of time after their wells achieve actual payout.

The Old Framework is applicable to all conventional oil and natural gas wells drilled prior to January 1, 2017 and bitumen production. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for conventional oil production under the Old Framework range from a base rate of 0% to a cap of 40%.

The Old Framework also includes a natural gas royalty formula which provides for a reduction based on the measured depth of the well below 2,000 metres deep, as well as the acid gas content of the produced gas. Subject to certain available incentives, effective from the January 2011 production month royalty rates for natural gas production under the Old Framework range from a base rate of 5% to a cap of 36%.

Under the Old Framework, the royalty rate applicable to natural gas liquids is a flat rate of 40% for pentanes and 30% for butanes and propane.

Currently, 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.

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

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

Incentive Programs

Pursuant to the Old Framework a number of incentive programs, such as the Deep Oil Exploratory Well Program, the Enhanced Oil Recovery Royalty Program ("**EOR Program**"), the Natural Gas Deep Drilling Program, and the Innovative Energy Technologies Program (the "**IETP**"), were created.

The Deep Oil Exploratory Well Regulation provides a limited royalty exemption for qualifying exploratory oil wells spudded or deepened between January 1, 2009 and December 31, 2013 that are deeper than 2,000 metres and have a producing interval below 2,000 metres.

With respect to the EOR Program, the Enhanced Oil Recovery Royalty Regulation, 2014 provides that Alberta Energy may approve royalty reductions for qualifying enhanced oil recovery projects.

The Natural Gas Deep Drilling Regulation, 2010 provides a limited royalty reduction for qualifying exploratory and development natural gas wells spudded or deepened after May 1, 2010, with producing intervals that are deeper than 2,000 metres.

Under the Modernized Framework, two strategic programs have been recently introduced with the intention of promoting expanded production potential and generating long-term returns to the Province of Alberta.

The new Enhanced Hydrocarbon Recovery Program (the "**EHR Program**") began January 1, 2017 and replaced the existing EOR Program. The EHR Program is intended to promote incremental production through enhanced recovery methods and consists of two main components. The first component targets tertiary recovery schemes which enhance recovery of hydrocarbons from an oil or gas pool by miscible flooding, immiscible flooding, solvent flooding, chemical flooding or other approved methods. The second component targets secondary recovery schemes which enhance recovery of hydrocarbons from an oil or gas pool by water flooding, gas cycling, gas flooding, polymer flooding or other approved methods. Under both components of the program, a company pays a flat royalty of 5 per cent on crude oil, natural gas and natural gas liquids produced from wells in an approved scheme for a limited benefit period. After the benefit period ends, wells in these schemes are subject to normal royalty rates under the Modernized Framework.

The new Emerging Resources Program (the "**ERP**") began January 1, 2017. The ERP is intended to encourage industry to open up new oil and gas resources in higher-risk and higher-cost areas that have large resource potential. For the purposes of the ERP, a project consists of a defined geographic area, target formation, set of wells and associated infrastructure. Wells that receive program benefits pay a flat royalty rate of 5 per cent until their combined revenue equals their combined program specific cost allowances established under the ERP, which will replace the standard Drilling and Completion Cost Allowance under the Modernized Framework in respect of such wells. After achieving payout of the specific cost allowance, wells are subject to normal royalty rates under the Modernized Framework.

Environmental Regulation

As an operator of oil and natural gas properties in Canada, we are subject to stringent federal, provincial, territorial, and local laws and regulations relating to environmental protection as well as controlling the manner in which various substances, including wastes generated in connection with oil and gas exploration, production, and transportation operations, are released into the environment. Compliance with these laws and regulations can affect the location or size of wells and facilities, prohibit or limit the extent to which exploration and development may be allowed, and require proper abandonment of wells and restoration of properties when production ceases. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, or criminal penalties, imposition of remedial obligations, incurrence of capital or increased operating costs to comply with governmental standards, and even injunctions that limit or prohibit exploration and production activities or that constrain the disposal of substances generated by oil field operations.

Environmental legislation in the Province of Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta) and the *Oil and Gas Conservation Act* (Alberta). Environmental compliance in Saskatchewan is governed in general by the *Environmental Management and Protection Act* (Saskatchewan) and the *Oil and Gas Conservation Act* (Saskatchewan). Further federal environmental legislation is embodied in the *Canadian Environmental Protection Act*, 1999 and the Canadian Environmental Assessment Act, 2012.

The Corporation currently operates or lease, and has in the past operated or leased, a number of properties that have been used for the exploration and production of oil and gas. Although Yangarra utilizes and has utilized standard industry operating and disposal practices, hydrocarbons or other wastes may have been disposed of or released on or under the properties operated or leased by us or on or under other locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under our control. These properties and the wastes disposed thereon may be subject to laws and regulations imposing joint and several, strict liability without regard to fault or the legality of the original conduct that could require us to remove previously disposed wastes or remediate property contamination, or to perform well plugging or pit closure or other actions of a remedial nature to prevent future contamination.

The Corporation may be affected by the Lower Athabasca Region Plan ("**LARP**") under the Alberta *Land Stewardship Act*, which came into effect on September 1, 2012 and is currently being implemented. LARP is a legislative instrument equivalent to regulations and will be binding on the government of Alberta and provincial regulators, including those governing the oil and gas industry. LARP is the first of an anticipated seven regional land-use plans in the province and applies to over two million hectares of land and, among other things, implements management frameworks for air emissions, water use, and land disturbance to control cumulative environmental effects of industrial development.

On September 1, 2012, framework for air quality, surface water quality and groundwater came into force, subjecting future and existing and future operations in the region to more onerous environmental constraints and stringent operating parameter. As part of these frameworks, parties may be required to participate in regional monitoring and report on the progress of implementation. Further, conversation areas established under LARP may impact some oil sands license holders in the region, as there is the potential for specific oil sands leases to be cancelled by the government. Should such a situation occur, the Alberta government would be responsible for compensating affected license holders.

On February 3, 2012 the government of Alberta and the government of Canada released the Joint Canada-Alberta Implementation Plan for Oil Sands Monitoring (the "**Monitoring Plan**"). The Monitoring Plan is designed to provide an improved understanding of the potential cumulative environmental effects of oil sands development and will increase air, water, land and biodiversity monitoring in the oil sands region. The Monitoring Plan is expected to be phased in over a three-year period and funding will be provided by industry. To support the Monitoring Plan industry has agreed to provide aggregate funding of up to $50 million a year. On October 17, 2012, the government of Alberta announced that it will establish an independent arm's-length environmental monitoring agency in the province. The independent agency is expected to begin work in the oil sands region with a focus on integrated and coordinated monitoring of land, air, water and biodiversity.

The Corporation believes that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards. A recent example of this trend is the high-level of regulatory attention that the practice of hydraulic fracturing continues to receive in various jurisdictions. The Province of Alberta has recently announced its intention to adopt mandatory disclosure requirements and an online registry for hydraulic fracturing activities. Additionally, the AER, recently released a new Hydraulic Fracturing Directive, effective August 21, 2013, which sets out AER requirements for managing the subsurface integrity of wells associated with hydraulic fracturing. While Yangarra believes that it is in substantial compliance with applicable environmental laws and regulations in effect at the present time and that continued compliance with existing requirements will not have a material adverse impact on the Corporation, the Corporation cannot give any assurance that it will not be adversely affected in the future.

The Corporation has established internal guidelines to be followed in order to comply with environmental laws and regulations in the jurisdictions in which it operates. Yangarra employs an environmental, health, and safety department whose responsibilities include providing assurance that operations are carried out in accordance with applicable environmental guidelines and safety precautions. Although Yangarra maintains pollution insurance against the costs of cleanup operations, public liability, and physical damage, there is no assurance that such insurance will be adequate to cover all such costs or that such insurance will continue to be available in the future.

The regulatory landscape in Alberta has undergone a transformation from multiple regulatory bodies to a single regulator for upstream oil and gas, oil sands and coal development activity. On June 17, 2013, the Alberta Energy Regulator (the "**AER**") assumed the functions and responsibilities of the former Energy Resources Conservation Board, including those found under the *Oil and Gas Conservation Act* ("**ABOGCA**"). On November 30, 2013, the AER assumed the energy related functions and responsibilities of Alberta Environment and Sustainable Resource Development ("**AESRO**") in respect of the disposition and management of public lands under the *Public*

Lands Act. On March 30, 2014, the AER assumed the energy related functions and responsibilities of AESRO in the areas of environment and water under the *Environmental Protection and Enhancement Act* and the *Water Act*, respectively. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind the transformation to a single regulator is the creation of an enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

Accountability and Transparency

The federal Extractive Sector Transparency Measures Act (the "ESTMA") imposes mandatory reporting requirements on certain entities engaged in the commercial development of oil, gas or minerals, which includes exploration, extraction and holding permits to explore or extract. All companies subject to ESTMA are required to report payments over $100,000 made to any level of a Canadian or foreign government, including royalty payments, taxes (other than consumption taxes and personal income taxes), fees, production entitlements, bonuses, dividends (other than ordinary dividends paid to shareholders) and infrastructure improvement payments. These categories are distinct and regardless of the aggregate payment amount, one or more individual categories must reach the $100,000 threshold for reporting to be required.

Any persons or entities found in violation of the ESTMA (which includes making a false report, failing to make the report public or failing to maintain records for the prescribed period) can be fined up to $250,000 for each day that the offence continues. There is a further fine of up to $250,000 for any person or entity who has structured payments in order to avoid the obligation to report such payments under the ESTMA. Officers or directors who authorized or acquiesced in the commission of an offence can be subject to personal liability, regardless of whether the entity for which they acted has been prosecuted or convicted. The ESTMA contains a due diligence defence whereby no person will be found guilty of an offence under the ESTMA if the person can establish that he or she exercised due diligence to avoid committing the offence. Additionally, there is a five year limitation period within which proceedings must be brought for offences under the ESTMA.

Climate Change Regulation

Federal (Canada)

In December 2015, Canada and 195 other countries that are members of the United Nations Framework Convention on Climate Change met in Paris, France and signed the Paris Agreement on climate change. The stated objective of the Paris Agreement is to hold “the increase in global average temperature to well below 2 degrees Celsius above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5 degrees Celsius.” The countries which agreed to the Paris Agreement committed to meeting every five years to review their individual progress on GHG emissions reductions and to consider amendments to non-binding individual country targets. Canada is required to report and monitor its GHG emissions, though the implementation of such reporting and monitoring has yet to be determined. The Paris Agreement also contemplates that by 2020 the parties thereto will develop a new market-based mechanism related to carbon trading, which is expected to be based largely on lessons learned from the Kyoto Protocol. The Government of Canada has announced that it will develop a country-wide approach to implementing the Paris Agreement in 2016.

The Corporation is unable to predict the impact of the Paris Agreement on its operations. It is possible that mandatory emissions reduction requirements may have a material adverse effect on the Corporation’s financial condition, results of operations and cash flow.

Over the last several years, the federal government has undertaken a number of initiatives to achieve domestic GHG reductions. These measures include regulations, codes and standards, targeted investments, incentives, tax measures and programs that directly reduce GHG emissions.

On October 3, 2016 the Government of Canada announced a pan-Canadian approach to the pricing of GHG emissions. The federal plan provides all Canadian provinces and territories a year to introduce their own carbon pricing models of either a cap and trade program or a carbon tax meeting a standard to be prescribed, failing which the federal government will begin to levy its own carbon tax on a broad set of emission sources. The initial default carbon tax is expected to begin at $10 per tonne of GHG emissions on January 1, 2018 and increase by $10 per tonne per year until it reaches $50 per tonne in 2022.

In addition, on June 29, 2016 Canada joined the United States and Mexico in agreeing to reduce methane emissions from the oil and gas sector by up to 45% by 2025 by developing and implementing federal regulations for both existing and new sources of venting and fugitive methane emissions. Previously, on March 10, 2016 Canada and the United States committed to take action on methane emissions through federal regulations as expeditiously as possible. The federal methane regulations are expected to be published in 2017.

Alberta

Alberta introduced the Climate Change and Emissions Management Act, which provides a framework for managing GHG emissions by reducing specified gas emissions, relative to gross domestic product, to an amount that is equal to or less than 50% of 1990 levels by December 31, 2020. The accompanying regulations include the Specified Gas Emitters Regulation (the "**SGER**"), which imposes GHG emissions limits, and the Specified Gas Reporting Regulation (the "**SGRR**"), which imposes GHG emissions reporting requirements. The SGER, effective July 1, 2007 to June 2015, applies to facilities in Alberta that have produced 100,000 or more tonnes of GHG emissions in 2003 or any subsequent year, and requires reductions in GHG emissions intensity (i.e. the quantity of GHG emissions per unit of production) from emissions intensity baselines that are established in accordance with the SGER.

The SGER distinguishes between "established" facilities that completed their first year of commercial operation before January 1, 2000 or have completed eight years of commercial operation, and "new" facilities that have completed their first year of commercial operation on December 31, 2000 or a subsequent year and have completed less than eight years of commercial operation. Generally, the baseline for an established facility reflects the average of emissions intensity in 2003, 2004, and 2005, and the baseline for a new facility reflects emissions intensity in the third year of commercial operation. For an established facility, the required reduction in GHG emissions is 12% per year from its baseline, and such reduction must be maintained over time. For a new facility, the required reduction from its baseline is phased in by annual 2% increments beginning in the fourth year of commercial operation until the annual 12% reduction requirement is reached, and once reached such 12% reduction must be maintained over time.

There are three methods for operators of facilities that are subject to the SGER to comply with the annual emission intensity reduction requirements: (i) improve emissions intensity at the facility; (ii) purchase emission performance or emission offset credits in the open market, which are generated from Alberta based projects; and/or (iii) purchase "fund credits" by contributing to the Alberta Climate Change and Emissions Management Fund ("Fund") run by the Alberta government. Historically the contribution costs to the Fund have been set at $15/tonne of Co2e although that has recently changed and the contribution costs are now set by order of the government of Alberta. Compliance reports for facilities subject to the SGER are due to Alberta Environment on March 31 annually.

The SGRR imposes GHG emissions reporting requirements on facilities that have GHG emissions of 50,000 tonnes or more in a year. In addition, Alberta facilities must currently report emissions of industrial air pollutants and comply with obligations imposed in permits and under other environmental regulations. Further, in January 2008, Alberta announced a new climate change plan setting out a goal of achieving a 14% absolute reduction in GHG emissions below 2005 levels in the province by 2050.

The SGRR imposes GHG emissions reporting requirements on facilities that have GHG emissions of 50,000 tonnes or more in a year. In addition, Alberta facilities must currently report emissions of industrial air pollutants and comply with obligations imposed in permits and under other environmental regulations. Further, in January 2008, Alberta announced a new climate change plan setting out a goal of achieving a 14% absolute reduction in GHG emissions below 2005 levels in the province by 2050.

Alberta Climate Leadership Plan

In November 2015, the Alberta government announced its climate leadership plan (the "**CLP**") and released to the public the climate leadership report to the Minister of Environment and Parks (the "**Report**") that it commissioned from the Climate Change Advisory Plan and on which the CLP is based. The CLP includes four strategies that the government will implement to address climate change: (i) the complete phase-out of coal-fired sources of electricity by 2030: (ii) implementing an Alberta economy-wide price on greenhouse gas ("**GHG**") emissions of $30 per tonne; (iii) reducing oil sands emissions to a province-wide total of 100 megatonnes per year (compared to current industry emissions levels of approximately 70 megatonnes per year), with certain exceptions for cogeneration power sources and new upgrading capacity; and (iv) reducing methane emissions from oil and gas activities by 45% by 2025. Uncertainties exist with respect to the implementation of the CLP and the effects that the CLP, including the overall emissions limit, may have on the oil and gas industry.

Adverse impacts to the Corporation's business as a result of comprehensive GHG legislation or regulation, including legislation to implement the CLP and applied to the Corporation's business in Alberta or any jurisdiction in which the Corporation operates, may include, but are not limited to: increased compliance costs; permitting delays; substantial costs to generate or purchase emission credits or allowances adding costs to the products the Corporation produces; and reduced demand for crude oil and certain refined products. Emission allowances or offset credits may not be available for acquisition or may not be available on an economic basis. Required emission reductions may not be technically or economically feasible to implement, in whole or in part, and failure to meet such emission reduction requirements or other compliance mechanisms may have a material adverse effect on the Corporation's business resulting in, among other things, fines, permitting delays, penalties and the suspensions of operations. Consequently, no assurances can be given that the effect of future climate change regulations will not be significant to the Corporation.

Beyond existing legal requirements, the extent and magnitude of any adverse impacts of any additional programs or additional regulations cannot be reliably or accurately estimated at this time because specific legislative and regulatory requirements have not been finalized and uncertainty exists with respect to the additional measures being considered and the time frames for compliance.

Federal Review of Environmental and Regulatory Processes

In 2016, the Government of Canada commenced a review of environmental and regulatory processes under various acts and released four reports in 2017 for public comment. The reports contained reviews of the NEB process, the federal environmental assessment process, the Fisheries Act, and the Navigation Protection Act. In June 2017, the Government of Canada issued a discussion paper for comment that outlined the legislative changes it is considering with respect to the four areas under review.

Some of the proposed changes to the federal environmental assessment process include, among other things: enhanced consideration of cumulative effects through regional environmental assessments and national frameworks; a process to amend the list of projects subject to federal environmental assessments; assessment of impacts on Indigenous peoples; providing for greater Indigenous participation on assessment boards and review panels; and eliminating the standing est to determine who can participate in assessments. A number of other changes regarding participant funding, scope of assessments and legislated timing of assessments are also being considered.

The Government of Canada requested comments on the discussion paper by August 2017 and indicated it would propose legislative changes in the fall of 2017; however, no legislative changes have been proposed to date.

Federal government announced in February 2018 its overhaul of the review of environmental and regulatory processes for major projects.

Liability Management Rating Programs

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

Yangarra’s liability management rating (“LMR”) is currently 8.08 versus an industry average of 4.68.

On May 17, 2016, the Alberta Court of Queen's Bench issued a decision in the case of Redwater Energy Corporation (Re), 2016 ABQB 278 ("Redwater") which provided that trustees and receivers of insolvent licensees may disclaim or renounce uneconomic oil and gas assets to the AER. These wells and facilities then become "orphans" to be remediated by the Orphan Well Associate ("OWA"). On April 24, 2017, the Alberta Court of Appeal upheld the Redwater decision in Orphan Well Assn v Grant Thornton Ltd, 2017 ABCA 124 ("Redwater Appeal"). In November 2017, the AER was granted leave to appeal the Redwater Appeal to the Supreme Court of Canada.

On June 20, 2016, as part of its response to the Redwater decision, the AER released Bulletin 2016-16: Licensee Eligibility – Alberta Energy Regulator Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision ("Bulletin 2016-16") which, among other things, implements important changes to the AER's procedures relating to liability management ratings, license eligibility and transfers. These changes may impact the Company's ability to transfer its licenses, approvals or permits, and may result in increased costs and delays or require changes to projects or transactions.

Because of Redwater and based on the current economic environment, the number of orphaned wells in Alberta has increased significantly and accordingly, the aggregate value of the asset abandonment, reclamation and remediation liabilities assumed by the OWA has increased and may continue to increase. The OWA may seek compensation for such liabilities from industry participants, including the Company, through an increase in the annual levy, further changes to regulations or other means. While the impact on the Company of any legislative, regulatory or policy decisions as a result of the Redwater decision and its pending appeal cannot be reliably or accurately estimated, any cost recovery or other measures taken by applicable regulatory bodies may impact the Company and materially and adversely affect, among other things, the Company's business, financial condition, results of operations and cash flow.

The AER has also implemented the inactive well compliance program to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under Directive 013 – Suspension Requirements for Wells ("Directive 013"). This program applies to all inactive wells that are non-compliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive noncompliant wells into compliance with the requirements of Directive 013 within five years. As of April 1, 2015, each licensee is required to bring 20%

of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with Directive 020 – Well Abandonment. The list of current wells subject to the AER's inactive well compliance program is available on the AER's Digital Data Submission system

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal Proceedings

In the normal conduct of operations, there are other pending claims by and against the Corporation. Litigation is subject to many uncertainties, and the outcome of individual matters is not predictable with assurance. In the opinion of management, based on the advice and information provided by its legal counsel, the final determination of these other litigations will not materially affect the Corporation.

Regulatory Actions

To the knowledge of management of the Corporation, no penalties or sanctions have been imposed by a court relating to securities legislation or by a securities regulatory body or by any other court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision, nor have any settlement agreements been entered into by the Corporation with a court relating to securities legislation or with a securities regulatory authority during the most recently completed financial year.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as set out below, none of the directors, executive officers of the Corporation, any person or company that is the direct or indirect beneficial owner of, or who exercises control or direction over, more than 10 percent of any class or series of outstanding voting securities of the Corporation, nor any associate or affiliate of the foregoing persons had any material interest, direct or indirect, in any transaction during the three most recently completed financial years or during the current financial year that has materially affected or will materially affect the Corporation.

Certain directors and officers participated in the May 2015 Financing. The total aggregated gross proceeds of the May 2015 Financing were approximately $20,000,000 and a total of 9,926,000 Common Shares were issued. James Evaskevich, Gordon Bowerman, Robert Weir and Neil Mackenzie subscribed for 162,450 Common Shares for gross proceeds of $321,173 (2%) of the May 2015 Financing.

Certain directors and officers participated in the May 2016 Financing. The total aggregated gross proceeds of the May 201 Financing were approximately $11,500,000 and a total of 11,500,000 Common Shares were issued. James Evaskevich, Gordon Bowerman, Robert Weir, Neil Mackenzie, James Glessing and Randall Faminow subscribed for 385,000 Common Shares for gross proceeds of $385,000 (3%) of the May 2016 Financing.

TRANSFER AGENT AND REGISTRAR

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

MATERIAL CONTRACTS

The Corporation did not enter into any material contracts outside the ordinary course of business within the most recently completed financial year or prior thereto that are still in effect.

INTERESTS OF EXPERTS

Deloitte prepared the 2017 Reserves Report referred to in this Annual Information Form. As of the date hereof, the partners, employees and consultants of Deloitte who participated in or who were in a position to directly influence the preparation of the 2017 Reserves Report do not hold any of the securities of the Corporation.

MNP LLP has confirmed that it is independent of the Corporation in accordance with the relevant rules and related interpretation prescribed by the Institute of Chartered Accountants of Alberta.

ADDITIONAL INFORMATION

Additional information relating to the Corporation may 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, if applicable, is contained in the Corporation's information circular dated April 10, 2017. Additional financial information is also provided in the Corporation's consolidated financial statements and MD&A for the year ended December 31, 2017.

SCHEDULE "A"
REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the Board of Directors of Yangarra Resources Ltd. (the “**Company**”):

1. We have evaluated the Company’s reserves data as at December 31, 2017. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2017, 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 as amended from time to time (the “**COGE Handbook**”) maintained by the Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2017, and identifies the respective portions thereof that we have evaluated and reported on to the Company’s Management /Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Yangarra Resources Ltd. Reserve Estimation and Economic Evaluation	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue ($M, before income taxes, 10% discount rate)			
			Audited	**Evaluated**	**Reviewed**	**Total**
Deloitte LLP	December 31, 2017	Canada	**-**	**$1,026,588**	**-**	**$1,026,588**

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. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after the effective date of our reports.

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

Executed as to our report referred to above:

Deloitte LLP
700, 850 – 2nd Street S.W.
Calgary, Alberta
T2P 3P8

(signed) “Andrew Botterill”
Andrew Botterill, P. Eng.
Partner

Execution date: February 21, 2018

SCHEDULE "B"
REPORT OF MANAGEMENT AND DIRECTORS
ON OIL AND GAS DISCLOSURE

Management of Yangarra Resources Ltd. (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 December 31, 2017, 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 will be filed with securities regulatory authorities concurrently with this report.

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, in the event of a proposal to change the independent qualified reserves evaluator, to inquire whether there had been disputes between the previous independent qualified reserves evaluator and management; and

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

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 approved:

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

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

(c) the content and filing of this report.

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

(signed) "James Evaskevich"
James Evaskevich
President and CEO

(signed) "James Glessing"
James Glessing
CFO

(signed) "Robert Weir"
Robert Weir
Director

(signed) "Gordon Bowerman"
Gordon Bowerman
Director

March 8, 2018

SCHEDULE "C"

AUDIT COMMITTEE CHARTER

All of the Audit Committee members shall be independent and financially literate within the meaning of National Instrument 52-110 or its successor or replacement policy (the "**Instrument**") or as the case may be exempt from the requirements of sections 1.4 and 1.5 of the Instrument in accordance with the Instrument provisions.

Meaning of Financial Literacy — For the purposes of this Mandate, an individual is financially literate if he or she has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the issuer's financial statements.

The Audit Committee shall meet at least four times per year, on a quarterly basis, to fulfill its mandate.

The Audit Committee shall recommend to the Board of Directors:

(a) the external auditor to be nominated for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for the Corporation; and

(b) the compensation of the external auditor.

The Audit Committee is directly responsible for overseeing the work of the external auditor engaged for the purposes of preparing or issuing an auditor's report or performing other audit, review or attest services for the Corporation, including the resolution of disagreements between management and the external auditor regarding financial reporting.

The Audit Committee shall pre-approve all non-audit services to be provided to the Corporation or its subsidiaries' entities by the Corporation's external auditor.

The Audit Committee shall review the Corporation's financial statements, MD&A and annual and interim profit or loss press release before the Corporation publicly discloses this information.

The Audit Committee must satisfy itself that adequate procedures are in place for the review of the Corporation's public disclosure of financial information extracted or derived from the Corporation's financial statements, other than the public disclosure referred to in the paragraph above, and must periodically assess the adequacy of those procedures.

The Audit Committee must establish procedures for:

(a) the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal controls, or auditory matters; and

(b) the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.

The Audit Committee shall review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and former external auditors of the Corporation.