YANGARRA RESOURCES LTD.

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2023

March 6, 2024

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SCHEDULES

GLOSSARY OF TERMS

Unless the context otherwise requires, in this Annual Information Form the following terms and abbreviations have the meanings set forth below.

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

"**AER**" means the Alberta Energy Regulator.

"**Annual Information Form**" means this annual information form dated March 6, 2024.

"**Board**" means the board of directors of the Corporation.

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook, maintained by the Society of Petroleum Evaluation Engineers (Calgary chapter), as amended from time to time

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

"**Corporation**", "**Yangarra**", "we", "us" or "our" means Yangarra Resources Ltd., a corporation existing under the ABCA, and, where the context requires, its subsidiaries, taken as a whole.

"**Credit Facility**" means collectively senior syndicated facility with a syndicate of lenders, all as more particularly described under the heading "*Business of the Corporation – Three Year History*".

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

"**SEDAR+**" means the System for Electronic Document Analysis and Retrieval+, accessible at www.sedarplus.ca.

"**TSX**" means the Toronto Stock Exchange.

"**United States**" or "**U.S.**" means the United States of America.

ABBREVIATIONS AND CONVENTIONS

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. **Given the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6 Mcf: 1 Bbl, utilizing a conversion ratio at 6 Mcf: 1 Bbl may be misleading as an indication of value.**
BOE/d, boe/d or boepd	barrel of oil equivalent per day.

Conventions

Unless otherwise specified, all dollar amounts in this Annual Information Form, including the symbol "$", are expressed in Canadian dollars.

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

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 Corporation's 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 grow through acquisitions, exploration and development;
- future growth and drilling plans;
- future funds from operations;
- capital programs;
- debt levels;
- future royalty rates;
- future depletion, depreciation and accretion rates;
- treatment under, and changes to, governmental regulatory regimes and tax laws;
- our business plans and strategy;
- the completion timelines, results and benefits of infrastructure projects in Canada;
- the ability of Canadian oil and natural gas producers to benefit from trade agreements; and
- capital expenditure programs.

Statements relating to "reserves" and "resources" are also 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 that the reserves can be profitably produced in the future.

Forward-looking statements are subject to risks, uncertainties and assumptions, including those discussed below and elsewhere in this Annual Information Form. Although we believe that the expectations represented in such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Some of the risks which could affect future results and could cause results to differ materially from those expressed in the forward-looking statements contained herein include the following:

- weakness in the oil and natural gas industry;
- market prices of oil and natural gas;
- differentials;
- fluctuation in the supply and demand for oil and natural gas;
- exploration, development and production risks;
- operational risks and liabilities inherent in oil and natural gas operations;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- our ability to market our oil and natural gas;
- geological, technical, drilling and processing problems;
- fluctuation in foreign exchange or interest rates;
- stock market volatility;
- environmental and climate change risks;
- inflation and cost management;
- the inability to access sufficient capital from internal and external sources;
- changes in general economic, market and business conditions;
- uncertainties and changes in royalty regimes;
- the accuracy of oil and gas reserves estimates and estimated production levels as they are affected by exploration and development drilling and estimated decline rates;
- the uncertainties in regard to the timing of our exploration and development program;
- fluctuations in the costs of borrowing;
- political or economic developments;
- ability to obtain regulatory and other third party approvals;
- the occurrence of unexpected events;
- the results of litigation or regulatory proceedings that may be brought against us;
- changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry;
- cyber-security issues; and
- the other factors discussed under "*Risk Factors*".

The forward-looking statements and information contained in this Annual Information Form and 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 the foregoing list of factors and risks. 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 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 the documents incorporated by reference herein are expressly qualified by this cautionary statement.

Non-IFRS Measures

Within this Annual Information Form, references are made to terms commonly used in the oil and natural gas industry. The term "netbacks" in this Annual Information Form is not a recognized measure under generally accepted accounting principles in Canada. We consider "netback" to be a key measure as it demonstrates Yangarra's profitability relative to current commodity prices. Corporate netbacks are comprised of operating, field operating, funds flow from operations and net income / (loss) netbacks. Operating netback is calculated as the average sales price of its commodities (including realized gains on financial instruments) and then subtracts royalties, operating costs and transportation expenses. Field operating netback subtracts the realized gains on financial instruments; funds flow from operations netback starts with the operating netback and further deducts general and administrative costs, finance expenses and adds finance income. To calculate the net income (loss) netback, Yangarra takes the funds flow from operations netback and deducts share-based compensation expense as well as depletion and depreciation charges, accretion expense, unrealized gains on financial instruments, any impairment or exploration and evaluation expense and deferred income taxes. There are no IFRS measures that are reasonably comparable to the netbacks calculated by the Corporation.

INCORPORATION AND ORGANIZATION

The Corporation was formed on May 1, 2010, as a result of an amalgamation under the ABCA between Yangarra and its wholly-owned subsidiary, Athabaska Energy Ltd. ("**Athabaska**"). 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 by issuing 50,000,004 common shares in the capital of Yangarra Predecessor at a deemed price of $0.05 per share.

On May 30, 2014, the Corporation filed articles of amendment to effect a consolidation of the Common Shares of the Corporation on a three old Common Shares for one new Common Share (3:1) basis.

TriOil was incorporated under the ABCA under the name "1000863 Alberta Ltd.", 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 three wholly-owned subsidiaries, "Yangarra Resources Corp.", "Yangarra Holding Corp.", and "Yangarra Production Partnership", each incorporated under the ABCA.

GENERAL DEVELOPMENTS OF THE CORPORATION

Three Year History

2021

On July 28, 2021, the Corporation announced the appointment of Brett Booth to Vice-President, Land, following the retirement of Randall Faminow.

On December 1, 2021, Yangarra announced that its syndicated senior credit facility was confirmed at $210 million.

2022

On February 1, 2022, the Corporation announced the publication of its inaugural ESG Report, allowing stakeholders to benchmark Yangarra's metrics with a peer group and highlighting Yangarra's stellar track record.

As announced on April 27, 2022, Gurdeep Gill was appointed President of the Corporation, with Jim Evaskevich retaining his title of Chief Executive Officer.

On May 17, 2022, Yangarra's Vice-President, Operations, Lorne Simpson, departed the Corporation.

On December 23, 2022, the Corporation announced that it had completed its semi-annual borrowing base review and the Corporation's Credit Facility was set at $180 million.

2023

On March 27, 2023, the Corporation closed a bought deal equity financing, completed by way of a short form prospectus, for the sale of 6,791,440 Common Shares issued on a flow-through basis in respect of Canadian development expenses at a price of $2.54 per flow-through share, for aggregate gross proceeds of $17,250,258.

On May 19, 2023, the Corporation completed its borrowing base review, and the Credit Facility was set at $145 million. As of September 30, 2023, the Credit Facility began reducing by $5 million per quarter until September 30, 2024, at which point the facility will remain at $120 million. The term out date was extended to May 31, 2024, and the maturity date was extended to May 31, 2025.

Significant Acquisitions

The Corporation did not complete any acquisitions during the most recently completed financial year that were significant acquisitions for the purposes of Part 8 of NI 51-102.

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. For the year ended December 31, 2023, Yangarra's oil and gas assets averaged production of 11,936 boe/d of oil, natural gas and NGLs (compared to average production of 11,022 boe/d of oil, natural gas and NGLs for the year ended December 31, 2022). As at December 31, 2023, Yangarra owned approximately 113,372 gross (97,860 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 economically grow over the next five years by drilling its extensive Cardium acreage. The Corporation may also explore and develop its Belly River, Mannville, Glauconitic and Duvernay assets in Central Alberta.

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 considering 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 many 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 and Russia 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;

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

(j) the impact of the Russia/Ukraine conflict; and

(k) LNG egress out of North America.

We mitigate such price risk through closely monitoring the various commodity markets and establishing price risk management programs, as deemed necessary, and through maintaining financial flexibility. Additionally, we continually review our capital program and implement initiatives to adapt to such price changes. See "*Risk Factors – Volatility of Oil and Gas Prices and Markets*", "*Risk Factors – Weakness in the Oil and Gas Industry",* "*Risk Factors – Hedging*", and "*Information Concerning the Oil and Natural Gas Industry – Curtailment*".

Revenue Sources

For the year ended December 31, 2023, 73% of the revenue from Yangarra's properties before royalties was derived from oil and NGLs and 27% were derived from natural gas (compared to 69% of the revenue being derived from oil and NGLs and 31% being derived from natural gas for the year ended December 31, 2022). 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 of 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 rates and costs.

Competitive Conditions

There is strong competition in 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.

Environmental Policies

We are committed to managing and operating in a safe, efficient, environmentally responsible manner in association with our industry partners and are committed to continually improving our environmental, health, safety and social performance. To fulfill this commitment, our operating practices and procedures are consistent with the requirements established for the oil and gas industry. Key environmental considerations include air quality and reduction of greenhouse gas emissions, water conservation, spill management, waste management, lease and right-of-way management, natural and historic resource protection, and liability management (including site assessment, remediation and reclamation). These practices and procedures apply to our employees, and we monitor all activities and make reasonable efforts to ensure that companies who provide services to us will operate in a manner consistent with our health, safety and environmental policies.

We believe that we meet all existing environmental standards and regulations and include sufficient amounts in our capital expenditure budget to continue to meet current environmental protection requirements. These requirements apply to all operators in the oil and gas industry; therefore, it is not anticipated that our competitive position within the industry will be adversely affected by changes in applicable legislation.

Our environmental management program and operating guidelines focus on minimizing the environmental impact of our operations while meeting regulatory requirements and corporate standards. Our environmental program is monitored by our health, safety and environmental committee and includes: an internal environmental compliance audit and inspection program; a suspended well inspection program to support future development or eventual abandonment; appropriate reclamation and decommissioning standards for wells and facilities ready for abandonment; an asset integrity program; an effective surface reclamation program; a groundwater monitoring program; a spill prevention, response and clean-up program; a fugitive emission survey and repair program; and an environmental liability assessment program.

We expect to incur abandonment and reclamation costs as our oil and gas properties are abandoned. In 2023, expenditures for normal compliance with environmental regulations were not material and expenditures for above normal compliance were $0.5 million.

Employees

As at December 31, 2022, Yangarra had 73 employees, including 13 head office and 60 field employees. As at the date hereof, Yangarra has 72 employees, comprised of 12 head office and 60 field employees.

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. **The risks set out below are not an exhaustive list, nor should they be taken as a complete summary or description of all the risks associated with our business and the oil and natural gas business generally.**

Our business could also be affected by additional risks and uncertainties not currently known to us or that we currently deem to be immaterial. If any of these risks occur, it could materially harm our business, financial condition, results of operations and funds flow, or impair our ability to implement business plans or complete development activities as scheduled. In that case, the market price of the Common Shares could decline, and you could lose all or part of your investment. Before deciding whether to invest in any of our securities, investors should carefully consider the risks set out below. If any of the risks described below materialize, our business, financial condition or results of operations could be materially and adversely affected. The information set forth below contains "forward-looking statements", which are qualified by the information contained under the heading "Forward-looking Statements" of this Annual Information Form.

Exploration, Development, and Production Risks

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

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

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

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

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

As is standard industry practice, we are not fully insured against all risks, nor are all risks insurable. Although we maintain liability insurance and business interruption insurance in an amount that we consider consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event, we could incur significant costs. See "*Risk Factors – Insurance*".

Adverse Economic Conditions

The demand for energy, including crude oil, NGLs and natural gas, is generally linked to broad-based economic activities. If there was a slowdown in economic growth, an economic downturn or recession, or other adverse economic or political development in the U.S., Europe, Asia or elsewhere, there could be a significant adverse effect on global financial markets and commodity prices. In addition, hostilities in the Middle East, Ukraine, and Taiwan and the occurrence or threat of terrorist attacks in the U.S. or other countries could adversely affect the global economy. Global or national health concerns, including the outbreak of pandemic or contagious diseases, such as COVID-19, may adversely affect us by (i) reducing global economic activity, thereby resulting in lower demand for crude oil, NGLs and natural gas, (ii) impairing our supply chain, for example, by limiting the manufacturing of materials or the supply of goods and services used in our operations, and (iii) affecting the health of our workforce, rendering employees unable to work or travel. These and other factors disclosed elsewhere herein that affect the supply and demand for crude oil, NGLs and natural gas, and our business and industry, could ultimately have an adverse impact on our financial condition, financial performance, and funds flow.

Impacts of Pandemics

In the event of a global pandemic, countries around the world may close international borders and order the closure of institutions and businesses deemed non-essential. This could result in a significant reduction in economic activity in Canada and internationally along with a drop in demand for oil and natural gas. Any reduction in economic activity in certain countries resulting from outbreaks, government-imposed lockdowns and other restrictions could have a negative effect on demand for oil and natural gas and could also aggravate the other risk factors identified herein. A resurgence of COVID-19 or a different pandemic may cause disruptions to production operations, access to materials and services, increased employee absenteeism from illness, and temporary closures of our facilities.

Credit Facilities

The amount authorized under the Corporation's Credit Facility 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, 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 oil 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, including LNG egress to global markets, 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 transportation 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.

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

Inflation and Rising Interest Rates

The inflation rate in Canada has increased over the last serval years, causing supply chain disruptions, inflationary cost pressures, equipment limitations, escalating supply costs and commodity prices, and additional government intervention through stimulus spending and additional regulations. These factors have increased our operating costs. Our inability to manage costs may impact project returns and future development decisions, which could have a material adverse effect on our financial performance and funds flow.

Additionally, the Bank of Canada has been increasing interest rates to combat this trend; the higher rates will have an impact on the Corporation's borrowing costs. The increase in borrowing costs may impact project returns and future development decisions, which could have a material adverse effect on our financial performance and funds flow. Rising interest rates could also result in a recession in Canada, the U.S. or other countries. A recession may have a negative impact on demand for oil and natural gas, causing a decrease in commodity prices. A decrease in commodity prices would immediately impact our revenues and funds flow and could also reduce drilling activity on our properties. It is unknown how long inflation will continue to impact the economies of Canada and the U.S. and how inflation and rising interest rates will impact oil and gas demand and commodity prices.

Political Uncertainty

The Corporation's results can be adversely impacted by political, legal, or regulatory developments in Canada and elsewhere that affect local operations and local and international markets. Changes in government, conflict, war, government policy or regulations, changes in law or interpretation of settled law, third-party opposition to industrial activity generally or projects specifically, and duration of regulatory reviews could impact our existing operations and planned projects. This includes actions by regulators or other political factors to delay or deny necessary licenses and permits for our activities or restrict the operation of third-party infrastructure that we rely on. Additionally, changes in environmental regulations, assessment processes or other laws, and increasing and expanding stakeholder consultation (including Indigenous stakeholders), may increase the cost of compliance or reduce or delay available business opportunities and adversely impact our results.

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. During its tenure, the former American administration withdrew the United States from the Trans-Pacific Partnership and passed sweeping tax reform, which, among other things, significantly reduced U.S. corporate tax rates. This has affected the competitiveness of other jurisdictions, including Canada. The former U.S. administration also took action to reduce regulation, which affected relative competitiveness of other jurisdictions.

Other government and political factors that could adversely affect our financial results include increases in taxes or government royalty rates (including retroactive claims) and changes in trade policies and agreements. Further, the adoption of regulations mandating efficiency standards and mandating the sale of electric vehicles, and the use of alternative fuels or uncompetitive fuel components, could affect the demand for our products. Many governments are providing tax advantages and other subsidies to support alternative energy sources or are mandating the use of specific fuels, technologies or electric vehicles. Governments and others are also promoting research into new technologies to reduce the cost and increase the scalability of alternative energy sources, and the success of these initiatives may decrease demand for our products.

A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the oil and natural gas industry, including the balance between economic development and environmental policy. The oil and natural gas industry has become an increasingly politically polarizing topic in Canada, which has resulted in a rise in civil disobedience surrounding oil and natural gas development – particularly with respect to infrastructure projects. Protests, blockades, demonstrations and vandalism have the potential to delay and disrupt our activities. See "*Information Concerning the Oil and Natural Gas Industry – Transportation Constraints and Market Access*".

The federal government was re-elected in 2021 but in a minority position. The ability of the minority federal government to pass legislation will be subject to whether it can come to agreement with and garner the support of the other elected parties, most of whom are opposed to the development of the oil and natural gas industry. The minority federal government will also be required to rely on the support of the other elected parties to remain in power, which provides less stability and may lead to an earlier subsequent federal election. Lack of political consensus, at both the federal and provincial level, continues to create regulatory and investment uncertainty, the effects of which become apparent on an ongoing basis, particularly with respect to carbon pricing regimes and transportation and export capacity, and may affect the business of participants in the oil and natural gas industry. See "*Information Concerning the Oil and Natural Gas Industry – Climate Change Regulation*", *"Information Concerning the Oil and Natural Gas Industry – Transportation Constraints and Market Access*", "*Information Concerning the Oil and Natural Gas Industry – Curtailment*" and "*Information Concerning the Oil and Natural Gas Industry – International Trade Agreements*".

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

If a defect exists in the chain of title or in our right to produce, or a legal challenge or legislative change arises, it is possible that we may lose all, or a portion of, the properties to which the title defect relates and/or our right to produce from such properties. This may have a material adverse effect on our business, financial condition, results of operations and prospects.

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 has been or 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. See "*Industry Conditions – Liability Management*".

Royalty Regimes

There can be no assurance that the governments in the jurisdictions in which we have assets will not adopt new royalty regimes, or modify the existing royalty regimes, which may have an impact on the economics of our projects. An increase in royalties would reduce our earnings and could make future capital investments, or our operations, less economical. See "*Information Concerning the Oil and Natural Gas Industry – Royalties and Incentives*".

Hydraulic Fracturing

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

Minor earthquakes are common in certain parts of Alberta and are generally clustered around the municipalities of Cardston, Fox Creek, Rocky Mountain House, Brazeau and Red Deer. Since 2015, the AER has introduced seismic protocols for hydraulic fracturing operators in the Seismic Protocol Regions initially in response to significant induced seismic activity in the Duvernay formation in Fox Creek in February 2015. Oil and natural gas producers in each of the Seismic Protocol Regions are subject to a "traffic light" reporting system that sets thresholds on the Richter scale of earthquake magnitude, which vary, among the three regions. The reporting requirements include an assessment of the potential for seismicity prior to conducting operations, the implementation of a response plan to address potential seismic events and the suspension of operations, depending on the magnitude of an earthquake. Orders imposed by the AER in response to seismic events remain in effect as long as the AER deems them necessary. In recent years, hydraulic fracturing has been linked to increased seismicity in the areas in which hydraulic fracturing takes place, leading to continued monitoring by the AER. The AER may extend seismic protocols to other areas of the province if necessary.

Drought

Drought conditions in the areas we operate could limit access to water that is essential to our Hydraulic fracturing operations.

Climate Change

Global climate issues continue to attract public and scientific attention. Numerous reports, including reports from the Intergovernmental Panel on Climate Change, have engendered concern about the impacts of human activity, especially hydrocarbon combustion, on global climate issues. In turn, increasing public, government, and investor attention is being paid to global climate issues and emissions of GHG, including emissions of carbon dioxide and methane from the production and use of oil, liquids and natural gas. GHG emission regulations in Canada and the U.S. are evolving, and as these regulations are established, they are likely to have a significant impact on organizations involved in the oil sands regions. 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 Corporation is unable to predict the impact of emissions reduction legislation on the Corporation, and it is possible that such legislation may have a material adverse effect on its business, financial condition, results of operations and cash flows.

Transition risks

Foreign and domestic governments continue to evaluate and implement policy, legislation, and regulations focused on restricting emissions commonly referred to as GHG emissions and promoting adaptation to climate change and the transition to a low-carbon economy. It is not possible to predict what measures foreign and domestic governments may implement in this regard, nor is it possible to predict the requirements that such measures may impose or when such measures may be implemented. However, international multilateral agreements, the obligations adopted thereunder and legal challenges concerning the adequacy of climate-related policy brought against foreign and domestic governments may accelerate the implementation of these measures. Given the evolving nature of climate change policy and the control of GHG emissions and resulting requirements, including carbon taxes and carbon pricing schemes implemented by varying levels of government, it is expected that current and future climate change regulations will have the effect of increasing our operating expenses, and, in the long-term, potentially reducing the demand for oil, liquids, natural gas and related products, resulting in a decrease in our profitability and a reduction in the value of our assets.

Claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance under certain laws or that such energy companies provided misleading disclosure to the public and investors of current or future risks associated with climate change. As a result, individuals, government authorities, or other organizations may make claims against oil and natural gas companies, including us, for alleged personal injury, property damage, or other potential liabilities. While we are not a party to any such litigation or proceedings, we could be named in actions making similar allegations. An unfavorable ruling in any such case could adversely affect the demand for and price of securities issued by us, impact our operations and have an adverse impact on our financial condition.

Given the perceived elevated long-term risks associated with policy development, regulatory changes, public and private legal challenges, or other market developments related to climate change, there have also been efforts in recent years affecting the investment community, including investment advisors, sovereign wealth funds, banks, public pension funds, universities and other institutional investors, promoting direct engagement and dialogue with companies in their portfolios on climate change action (including exercising their voting rights on matters relating to climate change) and increased capital allocation to investments in low-carbon assets and businesses while decreasing the carbon intensity of their portfolios through, among other measures, divestments of companies with high exposure to GHG-intensive operations and products. Certain stakeholders have also pressured insurance providers and commercial and investment banks to reduce or stop financing and providing insurance coverage to oil and natural gas and related infrastructure businesses and projects. The impact of such efforts requires our management to dedicate significant time and resources to these climate change-related concerns, may adversely affect our operations, and the demand for and price of our securities and may negatively impact our cost of capital and access to the capital markets.

Emissions, carbon and other regulations impacting climate and climate-related matters are constantly evolving. With respect to environmental, social, governance and climate reporting, the International Sustainability Standards Board has issued an IFRS Sustainability Disclosure Standard with the aim of developing sustainability disclosure standards that are globally consistent, comparable and reliable. In addition, the Canadian Securities Administrators published for comment Proposed National Instrument 51-107 – *Disclosure of Climate Related Matters,* intended to introduce climate-related disclosure requirements for reporting issuers in Canada with limited exceptions. If we are not able to meet future sustainability reporting requirements of regulators or current and future expectations of investors, insurance providers, or other stakeholders, our business and ability to attract and retain skilled employees, obtain regulatory permits, licences, registrations, approvals, and authorizations from various governmental authorities, and raise capital may be adversely affected. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*".

Physical Risks

The potential physical risks resulting from climate change are long-term in nature and associated with a high degree of uncertainty regarding the timing, scope, and severity of potential impacts. We do not conduct fundamental research regarding the scientific inquiry of climate change. Many experts believe global climate change could increase extreme variability in weather patterns, such as increased frequency of severe weather, rising mean temperature and sea levels, and long-term changes in precipitation patterns. Extreme hot and cold weather, heavy snowfall, heavy rainfall, and wildfires may restrict our ability to access our properties and cause operational difficulties, including damage to equipment and infrastructure. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions. Certain of our assets are located in locations that are proximate to forests and rivers, and a wildfire or flood may lead to significant downtime and/or damage to our assets or cause disruptions to the production and transport of our products or the delivery of goods and services in our supply chain.

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 on 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, which 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 counterparties 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.

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.

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.

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 by 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.

Credit Facility Arrangements

We currently have a credit facility and are required to comply with covenants under our Credit Facility, which include certain financial ratio tests, which, from time to time, either affect the availability, or price, of additional funding, and in the event that we do not comply with these covenants, our access to capital could be restricted or repayment could be required. Events beyond our control may contribute to our failure to comply with such covenants. A failure to comply with covenants could result in default under our Credit Facility, which could result in us being required to repay amounts owing thereunder. The acceleration of our indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross-default or cross-acceleration provisions. In addition, our Credit Facility may impose operating and financial restrictions on us that could include restrictions on the payment of dividends, repurchase or making of other distributions with respect to our securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

The impact of the Supreme Court of Canada's decision in the Redwater case on lending practices in the crude oil and natural gas sector and actions taken by secured creditors and receivers/trustees of insolvent borrowers has not yet been determined but could affect lending practices as secured creditors will be subject to prior satisfaction of abandonment and restoration claims which may not be capable of quantification at the time credit is advanced. See "*Risk Factors – Liability Management*".

If our lenders require repayment of all or a portion of the amounts outstanding under our Credit Facility for any reason, including for a default of a covenant, there is no certainty that we would be in a position to make such repayment. Even if we are able to obtain new financing in order to make any required repayment under our Credit Facilities, we may not be on commercially reasonable terms, or terms that are acceptable to us. If we are unable to repay amounts owing under Credit Facility, the lenders under our Credit Facility could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness.

Hedging

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

- production falls short of the hedged volumes, or prices fall significantly lower than projected;
- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement;

- the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or

- a sudden, unexpected event materially impacts oil and natural gas prices.

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

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 oftentimes, 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 it can. The Corporation offers no assurance that its entry into this business activity will be successful.

Management of Growth

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

Expiration of Licenses and Leases

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

Litigation

In the normal course of our operations, we may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions. Potential litigation may develop in relation to personal injuries (including resulting from exposure to hazardous substances, property damage, property taxes, land and access rights, environmental issues, including claims relating to contamination or natural resource damages and contract disputes). The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to us and could have a material adverse effect on our assets, liabilities, business, financial condition and results of operations. Even if we prevail in any such legal proceedings, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from business operations, which could have an adverse effect on our financial condition.

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.

Carbon Pricing Risk

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. See "*Information Concerning the Oil and Natural Gas Industry – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*". In Canada, the federal and certain provincial governments have implemented legislation aimed at incentivizing the use of alternative fuels and, in turn, reducing carbon emissions. The taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products and, at the same time, increasing our operating expenses, each of which may have a material adverse effect on our profitability and financial condition. Further, the imposition of carbon taxes puts us at a disadvantage with our counterparts who operate in jurisdictions where there are less costly carbon regulations.

Reputational Risk Associated with Our Operations

Our business, operations, or financial condition may be negatively impacted as a result of any negative public opinion towards us or as a result of any negative sentiment toward, or in respect of, our reputation with stakeholders, special interest groups, political leadership, the media or other entities. Public opinion may be influenced by certain media and special interest groups' negative portrayal of the industry in which we operate, as well as their opposition to certain oil and natural gas projects. Potential impacts of negative public opinion or reputational issues may include delays or interruptions in operations, legal or regulatory actions or challenges, blockades, increased regulatory oversight, reduced support for, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses and increased costs and/or cost overruns. Our reputation and public opinion could also be impacted by the actions and activities of other companies operating in the oil and natural gas industry, particularly other producers, over which we have no control. Similarly, our reputation could be impacted by negative publicity related to environmental damage, loss of life, injury or damage to property and environmental damage caused by our operations, or due to opposition from special interest groups opposed to oil and natural gas development. In addition, if we develop a reputation of having an unsafe work site, it may impact our ability to attract and retain the necessary skilled employees and consultants to operate our business. Opposition from special interest groups opposed to oil and natural gas development and the possibility of climate-related litigation against governments and fossil fuel companies may impact our reputation. See "*Risk Factors – Climate Change*".

Reputational risk cannot be managed in isolation from other forms of risk. Credit, market, operational, insurance, regulatory and legal risks, among others, must all be managed effectively to safeguard our reputation. Damage to our reputation could result in negative investor sentiment towards us, which may result in limiting our access to capital, increasing the cost of capital, and decreasing the price and liquidity of our Common Shares.

Non-Governmental Organizations

The oil and natural gas exploration, development and operating activities conducted by us may, at times, be subject to public opposition. Such public opposition could expose us to the risk of higher costs, delays or even project cancellations due to increased pressure on governments and regulators by special interest groups including Indigenous groups, landowners, environmental interest groups (including those opposed to oil and natural gas production operations) and other non-governmental organizations, blockades, legal or regulatory actions or challenges, increased regulatory oversight, reduced support of the federal, provincial or municipal governments, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses, and direct legal challenges, including the possibility of climate-related litigation. See "*Information Concerning the Oil and Natural Gas Industry – Transportation Constraints and Market Access*". There is no guarantee that we will be able to satisfy the concerns of the special interest groups and non-governmental organizations, and attempting to address such concerns may require us to incur significant, unanticipated capital and operating expenditures.

Changing Investor Sentiment

A number of factors, including concerns about the effects of the use of fossil fuels on climate change, the impact of oil and natural gas operations on the environment, environmental damage relating to spills of petroleum products during transportation, and Indigenous rights have affected certain investors' sentiments towards investing in the oil and natural gas industry. As a result of these concerns, some institutional, retail and public investors have announced that they are no longer willing to fund or invest in oil and natural gas properties or companies, or are reducing the amount thereof over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices. Developing and implementing such policies and practices can involve significant costs and require a significant time commitment from our Board, management and employees. Failing to implement the policies and practices, as requested by institutional investors, may result in such investors reducing their investment in us or not investing in us at all. Any reduction in the investor base interested or willing to invest in the oil and natural gas industry, and more specifically, us, may result in limiting our access to capital, increasing the cost of capital, and decreasing the price and liquidity of our Common Shares even if our operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause a decrease in the value of our assets, which may result in an impairment change.

Indigenous Lands and Rights Claims

Opposition by Indigenous groups to conduct our operations, development or exploratory activities in any of the jurisdictions in which we conduct business may negatively impact us in terms of public perception, diversion of management's time and resources, legal and other advisory expenses, and could adversely impact our progress and ability to explore and develop properties.

Some Indigenous groups have established or asserted Indigenous treaty, title and rights to portions of Canada. Although there are no Indigenous and treaty rights claims on lands where we operate, no certainty exists that any lands currently unaffected by claims brought by Indigenous groups will remain unaffected by future claims. Such claims, if successful, could have a material adverse impact on our operations or pace of growth.

The Canadian federal and provincial governments have a duty to consult with Indigenous people when contemplating actions that may adversely affect the asserted or proven Indigenous or treaty rights and, in certain circumstances, accommodate their concerns. The scope of the duty to consult by federal and provincial governments varies with the circumstances and is often the subject of ongoing litigation. The fulfillment of the duty to consult Indigenous people and any associated accommodations may adversely affect our ability to, or increase the timeline to, obtain or renew, permits, leases, licences and other approvals, or to meet the terms and conditions of those approvals. For example, regulatory authorities in British Columbia ceased granting approvals, and, in some cases, revoked existing approvals, for, among other things crude oil and natural gas activities relating to drilling, completions, testing, production, and transportation infrastructure following a June 2021 British Columbia Supreme Court decision that the cumulative impacts of government-sanctioned industrial development on the traditional territories of a First Nations group in Northeast British Columbia breached that group's treaty rights. While a settlement between the British Columbia government and the First Nations group has recently been announced, and the regulatory authorities have resumed granting certain approvals for crude oil and natural gas activities, the long-term impacts of, and associated risks with, the decision on the Canadian oil and natural gas industry and we remain uncertain.

In addition, the federal government has introduced legislation to implement the United Nations Declaration of the Rights of Indigenous Peoples ("**UNDRIP**"). Other Canadian jurisdictions, including British Columbia, have also introduced or passed similar legislation, or begun considering the principles and objectives of UNDRIP, or may do so in the future. The means and timelines associated with UNDRIP's implementation by the government is uncertain; additional processes may be created, or legislation amended or introduced associated with project development and operations, further increasing uncertainty with respect to project regulatory approval timelines and requirements. See "*Industry Conditions – Indigenous Rights*".

Information Technology Systems and Cyber-Security

We have become increasingly dependent upon the availability, capacity, reliability and security of our information technology infrastructure and our ability to expand and continually update this infrastructure, to conduct daily operations. We depend on various information technology systems to estimate reserve quantities, process and record financial data, manage our land base, manage financial resources, analyze seismic information, administer contracts with operators and lessees and communicate with employees and third-party partners.

Further, we are subject to a variety of information technology and system risks as a part of our normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of our information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to business activities or our competitive position. In addition, cyber phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames, passwords, and credit card details (and money) by disguising as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. If we become a victim to a cyber phishing attack it could result in a loss or theft of our financial resources or critical data and information, or could result in a loss of control of our technological infrastructure or financial resources. Our employees are often the targets of such cyber phishing attacks, as they are and will continue to be targeted by parties using fraudulent "spoof" emails to misappropriate information or to introduce viruses or other malware through "Trojan horse" programs to our computers.

We maintain policies and procedures that address and implement employee protocols with respect to electronic communications and electronic devices and conducts annual cyber-security risk assessments. We also employ encryption protection of our confidential information, all computers and other electronic devices. Despite our efforts to mitigate such cyber phishing attacks through education and training, cyber phishing activities remain a serious problem that may damage our information technology infrastructure. We apply technical and process controls in line with industry-accepted standards to protect our information, assets and systems, including a written incident response plan for responding to a cyber-security incident. However, these controls may not adequately prevent cyber-security breaches. Disruption of critical information technology services, or breaches of information security, could have a negative effect on our performance and earnings, as well as our reputation, and any damages sustained may not be adequately covered by our current insurance coverage, or at all. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on our business, financial condition and results of operations.

Forced or Child Labour in Supply Chains

In May 2023, *An Act to enact the Fighting Against Forced Labour and Child Labour in Supply Chains Act and to amend the Customs Tariff* was passed and came into force on January 1, 2024. Pursuant to the new legislation, any company that is subject to the reporting requirements, including us, is required to conduct certain due diligence on its supply chains and to file an annual report accordingly. While we are currently unaware of any forced or child labour in any of our supply chains, the increased scrutiny on the supply chains of Canadian companies could uncover the risk or existence of forced or child labour in a supply chain to which we have a connection, which could negatively impact our reputation.

Forward-looking Statements may prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on the Corporation's forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate. Additional information on the risks, assumptions and uncertainties are found under the heading "*Forward-looking Statements*" in this Annual Information Form.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated and was prepared on February 23, 2024. The effective date of the Statement is December 31, 2023. 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 at December 31, 2023, as evaluated and prepared by Deloitte LLP ("**Deloitte**") independent petroleum engineers of Calgary, Alberta in their report dated February 23, 2024, based on forecasted price assumptions (the "**2023 Reserves Report**"). The 2023 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 NI 51-101 and the COGE Handbook. The tables below summarize the data contained in the 2023 Reserves Report and, as a result, may contain slightly different numbers than the 2023 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 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, 2023, 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, 2023

Reserves Category	Light and Medium Oil (Mbbl)		Conventional Gas (MMcf)		Shale Gas (MMcf)		Natural Gas Liquids (Mbbl)		Total BOE (Mboe)	
	W.I. Gross	*Net*	*W.I. Gross*	*Net*	*W.I. Gross*	*Net*	*W.I. Gross*	*Net*	*W.I. Gross*	*Net*
Proved Developed Producing	5,719	4,959	146,172	133,902	403	383	7,871	6,539	38,019	33,879
Proved Developed Non-Producing	134	120	1,336	1,157	0	0	72	58	428	370
Proved Undeveloped	10,971	9,118	209,069	188,661	5,375	5,105	11,637	9,592	58,348	51,005
Total Proved	**16,824**	**14,198**	**356,577**	**323,719**	**5,778**	**5,488**	**19,579**	**16,188**	**96,796**	**85,253**
Probable	9,986	7,901	211,833	187,363	7,780	6,911	12,310	9,597	58,898	49,877
Total Proved Plus Probable	**26,810**	**22,099**	**568,410**	**511,082**	**13,557**	**12,399**	**31,890**	**25,785**	**155,694**	**135,130**

The following table is a summary of net present values of future net revenues associated with such reserves at December 31, 2023, 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, 2023

	Before Income Taxes				
Reserves Category	*0.0% (M$)*	*5.0% (M$)*	*10.0% (M$)*	*15.0% (M$)*	*20.0% (M$)*
Proved Developed Producing	886,575	639,771	504,078	419,575	362,165
Proved Developed Non-Producing	9,138	6,704	5,378	4,543	3,964
Proved Undeveloped	1,128,006	819,043	625,445	494,887	401,891
Total Proved	**2,023,719**	**1,465,518**	**1,134,901**	**919,005**	**768,019**
Probable	1,404,453	743,748	457,461	309,063	222,487
Total Proved Plus Probable	**3,428,171**	**2,209,266**	**1,592,362**	**1,228,067**	**990,506**

	After Income Taxes				
Reserves Category	*0.0% (M$)*	*5.0% (M$)*	*10.0% (M$)*	*15.0% (M$)*	*20.0% (M$)*
Proved Developed Producing	738,060	540,730	431,133	362,232	315,021
Proved Developed Non-Producing	7,036	5,133	4,091	3,432	2,973
Proved Undeveloped	868,565	621,993	467,310	363,029	288,856
Total Proved	**1,613,660**	**1,167,856**	**902,533**	**728,692**	**606,850**
Probable	1,080,940	568,373	346,116	231,196	164,471
Total Proved Plus Probable	**2,694,600**	**1,736,229**	**1,248,649**	**959,888**	**771,321**

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, 2023, based on forecast price assumptions and calculated without discount.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
BASED ON FORECAST PRICES AND COSTS
AS OF DECEMBER 31, 2023

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	1,613,103	159,868	545,831	0	20,829	886,575	148,515	738,060
Proved Developed Non-Producing	22,229	2,565	8,841	1,278	407	9,138	2,102	7,036
Proved Undeveloped	2,478,704	317,269	601,832	419,044	12,553	1,128,006	259,441	868,565
Total Proved	**4,114,036**	**479,702**	**1,156,504**	**420,323**	**33,788**	**2,023,719**	**410,058**	**1,613,660**
Probable	2,928,778	441,814	857,860	211,621	13,031	1,404,453	323,513	1,080,940
Proved Plus Probable	**7,042,814**	**921,516**	**2,014,364**	**631,943**	**46,819**	**3,428,172**	**733,571**	**2,694,600**

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, 2023, 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, 2023

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)	146,441	8.86 $/boe
	Shale Gas	-633	-0.49 $/boe
	Light and Medium Oil (including solution gas and by-products)	989,092	12.52 $/boe
	TOTAL	**1,134,901**	11.72 $/BOE
Proved Plus Probable	Associated and Non-Associated Gas (including by-products)	205,730	7.36 $/boe
	Shale Gas	15,447	4.50 $/boe
	Associated and Non-Associated Gas (including by-products)	1,371,184	11.03 $/boe
	TOTAL	**1,592,362**	10.23 $/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
2024	0.0%	0.0%	0.74
2025	2.0%	2.0%	0.77
2026	2.0%	2.0%	0.80
2027	2.0%	2.0%	0.80
2028 beyond	2.0%	2.0%	0.80

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	Alberta Reference – Gas Prices	Alberta AECO – Gas Prices	Pentanes + Condensate Edmonton	Butanes Edmonton	Propane Edmonton
	($US/bbl)	($Cdn/bbl)	($Cdn/mcf)	($Cdn/mcf)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/bbl)
Forecast							
2024	72.00	91.90	2.10	2.35	91.90	41.35	32.15
2025	71.40	88.75	3.05	3.30	88.75	44.35	35.50
2026	70.75	84.55	3.65	3.90	84.55	42.30	33.80
2027	72.15	86.20	3.70	4.00	86.20	43.15	34.50
2028	73.60	87.95	3.80	4.05	87.95	44.00	35.20

Escalation of 2.0% Thereafter

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, 2023, before transportation were $2.79/Mcf for natural gas, $45.72/Bbl for NGLs and $98.42/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, 2023 against such reserves at December 31, 2022 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	**18,529.2**	**12,141.0**	**30,670.2**	**17,629.6**	**12,287.2**	**29,916.8**
Production	-844.6	0.0	-844.6	-876.8	0.0	-876.8
Technical Revisions	-1,797.0	-1,850.5	-3,647.5	1,918.9	211.4	2,130.3
Extensions	1,480.6	-147.8	1,332.8	1,094.6	-82.4	1,012.3
Economic Factors	-544.4	-156.8	-701.2	-187.0	-106.1	-293.1
Closing Balance	**16,823.7**	**9,985.9**	**26,809.7**	**19,579.3**	**12,310.3**	**31,889.5**

	Conventional Gas			Shale 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	**296,461.7**	**195,555.1**	**492,016.8**	**5,786.3**	**7,692.1**	**13,478.4**
Production	-16,050.2	0.0	-16,050.2	-70.1	0.0	-70.1
Technical Revisions	59,125.1	19,586.8	78,712.0	127.6	162.6	290.2
Extensions	20,422.3	-1,537.0	18,885.3	0.0	0.0	0.0
Economic Factors	-3,381.9	-1,772.1	-5,154.0	-66.0	-75.2	-141.2
Closing Balance	**356,577.0**	**211,832.9**	**568,409.9**	**5,777.7**	**7,779.6**	**13,557.3**

	MBOE		
	Gross Proved	Gross Probable	Gross Proved Plus Probable
	(Mboe)	(Mboe)	(Mboe)
Opening Balance	**86,533.5**	**58,302.7**	**144,836.2**
Production	-4,408.1	0.0	-4,408.1
Technical Revisions	9,997.4	1,652.5	11,649.8
Extensions	5,978.9	-486.4	5,492.7
Economic Factors	-1,306.1	-570.8	-1,876.8
Closing Balance	**96,795.5**	**58,898.3**	**155,693.7**

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 2023, 2022, and 2021, based on forecast prices and costs.

Proved Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)	Natural Gas (non-associated & associated) (MMcf)	Natural Gas Liquids (Mbbl)
2021	13,768	214,018	12,492
2022	13,050	206,018	12,051
2023	10,971	214,444	11,637

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 58,348 Mboe of proved undeveloped reserves in the 2023 Reserves Report under forecast prices and costs, together with approximately $420 million of associated undiscounted future capital expenditures. Proven undeveloped capital spending in the first two forecast years of the 2023 Reserves Report accounts for approximately $261 million or 62% of the total forecast.

Probable Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)	Natural Gas (non-associated & associated) (MMcf)	Natural Gas Liquids (Mbbl)
2021	12,019	204,557	12,349
2022	12,141	203,247	12,287
2023	9,986	219,613	12,310

Deloitte has assigned 58,898 Mboe of probable undeveloped reserves and has allocated future development capital of approximately $212 million to all probable undeveloped reserves with $17 million 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.sedarplus.ca) 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) ($MM)	Total Proved Plus Probable Estimated Using Forecast Prices and Costs (Undiscounted) ($MM)
2024	192.7	206.2
2025	68.2	71.6
2026	76.1	76.1
2027	83.3	85.3
2028	-	100.5
Thereafter	-	92.2
Total for all years undiscounted	420.3	631.9

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, 2023, 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**
Central Alberta				
Producing	274	259	15	11
Non-Producing	-	-	15	15

Notes:

- Non-Producing 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.
- Gross wells are defined as the total number of wells in which the Corporation has an interest.
- 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, 2023. 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, 2023 based on escalating cost and price assumptions, as set forth in the 2023 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 (185 gross (168 net) sections), Belly River (16 Gross (15 net) sections) Viking, Second White Specs (45 gross (29 net) sections), Rock Creek and Ellerslie zones.

The field is located 60 miles 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 16 Mmcf/d constructed in early 2004. An oil battery was added to this facility in 2016 and subsequently moved to 16-8-37-7. Yangarra has a compressor facility in the Ferrier area of Central Alberta that was built early in 2013 capable of

22 Mmcf/d. An oil battery and truck service facility were constructed in December 2017 just north of the town of Rocky Mountain House. A compressor station in the West Ferrier area of Central Alberta was constructed in May/June of 2018 capable of 35 Mmcf/d. Yangarra constructed a compressor facility in the Chedderville area in early 2019 capable of 25 Mmcf/d. Yangarra constructed a compressor facility in the Chambers area in early 2023 capable of 15 Mmcf/d. All facilities process third party volumes providing the Corporation with incremental profit. The O'Chiese area has one compressor station capable of 10 Mmcf/d.

Yangarra has a 100% interest in a field office with accommodation, a shop and storage. As of December 31, 2023, 289 gross wells (270 net wells) are producing.

Properties with No Attributed Reserves

The following table sets out the Corporation's undeveloped land holdings as of December 31, 2023.

Location	Gross (hectares)	Net (hectares)
Alberta	45,881	39,644

As at December 31, 2023, there were no material commitments associated with the Corporation's undeveloped land holdings. The Corporation has rights to explore, develop, and exploit undeveloped land holdings that will expire.

Significant Factors to Properties with No Attributed Reserves

The Corporation will develop properties with no attributed reserves over the next 5 – 10 years.

Exploration and Development

In 2024, 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 2024 capital program is anticipated to be less than cash flows from operating activities generated in 2024.

Additional Information Concerning Abandonment and Reclamation Costs

The 2023 Reserves Report includes average well abandonment and reclamation costs of $60,000 per well, depending on the formation and depth of the well. The abandonment costs are based on average costs from the wells that were abandoned during 2022/23. The 2023 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 289 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 $21.2 million (undiscounted). The total proved plus probable abandonment and reclamation costs are $46.8 million (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 2023 Reserves Report as a deduction in arriving at future net revenue.

Forecast Prices and Costs – Proved (M$)

Year	Abandonment Costs (Undiscounted)
2024	-
2025	0.1
2026	0.2
2027	0.1
2028	0.2
Thereafter	33,799.4
Total	33,800.0

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

Year	Abandonment Costs (Undiscounted)
2024	-
2025	0.1
2026	0.1
2027	0.2
2028	0.1
Thereafter	46,799.5
Total	46,800.0

Forward Contracts

As at December 31, 2023, the Corporation was committed to the following commodity price risk contract:

Year	Volume		Term	Reference	Type	Strike Price
Natural Gas						
2023/2024	6,000	GJ/d	Nov23 - Jun24	AECO - Monthly 7A	Put	CAD $1.50
2023/2024	7,000	GJ/d	Nov23 - Jun24	AECO - Monthly 7A	Put	CAD $1.50
2024	7,000	GJ/d	Jan 24 - Jun 24	AECO - Monthly 7A	Put	CAD $1.50
2024	3,000	GJ/d	Jul 24 - Dec 24	AECO - Monthly 7A	Put	CAD $1.50
2024	4,400	GJ/d	Jul 24 - Dec 24	AECO - Monthly 7A	Put	CAD $1.50
Oil						
2023/2024	500	bbl/d	Nov 23 - Dec 24	WTI - USD	Put	USD - $50.00
2024	1,100	bbl/d	Jan 24 - Jun 24	WTI - USD	Put	USD - $50.00
2024	500	bbl/d	Jan 24 - Jun 24	WTI - USD	Put	USD - $50.00
2023/2024	400	bbl/d	Nov 23 - Jun 24	WTI - USD	Collar	USD $60.00 - 100.00 /bbl
2023/2024	800	bbl/d	Nov 23 - Jun 24	WTI - CAD	Collar	CAD $90.00 - 127.00 /bbl
2024	400	bbl/d	Jul 24 - Dec 24	WTI - USD	Put	USD - $50.00
2024	800	bbl/d	Jul 24 - Dec 24	WTI - USD	Put	USD - $50.00

Tax Horizon

Yangarra was not required to pay income tax in 2023 and based on current tax pools, projected cash flow, and projected exploration costs, the Corporation does not expect to be taxable in 2024.

Costs Incurred

For the year ended December 31, 2023, exploration and development capital expenditures were $94 million. The breakdown for the Corporation's capital expenditures during 2023 is presented below:

	($000's)
Land, acquisitions and lease rentals	$564
Drilling and completion	76,476
Geological and geophysical	242
Equipment	14,975
Other asset additions	1,692
Total	$93,950

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, 2023.

Exploration Wells	**Gross**	**Net**	**Development Wells**	**Gross**	**Net**
Light and Medium Oil	-	-	Light and Medium Oil	31	30.5
Natural Gas	-	-	Natural Gas	-	-
Service	-	-	Service	-	-
Dry	-	-	Dry	-	-
Total	-	-	Total	31	30.5

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	Natural Gas	Natural Gas Liquids	Light and medium oil	Natural Gas	Natural Gas Liquids
	(bbl/d)	(Mcf/d)	(bbl/d)	(bbl/d)	(Mcf/d)	(bbl/d)
Central Alberta	6,900	96,800	5,190	7,372	107,100	5,740

* 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, 2023 – December 31, 2023.

Average Daily Production				
Three months ended	March 31	June 30	Sept 30	Dec 31
Light and medium oil (bbl/d)	2,706	2,412	2,137	1,906
Natural gas (mcf/d)	43,180	44,799	44,451	41,283
Natural gas liquids (bbl/d)	2,509	2,225	2,564	2,346
Total (BOE/d)	12,412	12,103	12,110	11,133

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)	$100.12	$94.74	$105.54	$101.92
Natural gas ($/mcf)	$3.46	$2.33	$2.80	$2.36
Natural gas liquids ($/bbl)	$49.85	$42.20	$54.47	$32.97
($ / BOE)	$43.88	$35.32	$40.83	$32.41

Royalties Paid per Unit				
Three months ended	March 31	June 30	Sept 30	Dec 31
Total royalties ($/BOE)	$4.68	$3.10	$2.77	$2.47

Production and Transportation Costs				
Three months ended	March 31	June 30	Sept 30	Dec 31
Total costs ($/BOE)	$8.36	$7.99	$8.21	$8.39

Netbacks Received				
Three months ended	March 31	June 30	Sept 30	Dec 31
Total netbacks ($/BOE)	$30.88	$ 23.77	$29.86	$21.54

Production Volume by Field

The following table indicates the Corporation's average daily production from its important fields for the year ended December 31, 2023:

	Light and Medium Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	BOE (BOE/d)
Central Alberta	2,288	43,426	2,411	11,936

Uncertainty of Reserves Estimates

The reserve and recovery information contained in the 2023 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, 2023 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	Position	Principal Occupation	Director or Officer Since
James G. Evaskevich [(1)] Calgary, Alberta	Chief Executive Officer and Director	Chief Executive Officer of the Corporation since April 2022. Prior thereto, President of the Corporation since December 2001.	December 19, 2001
Gurdeep Gill [(1)] Calgary, Alberta	President	President of the Corporation since April 2022. Prior thereto, VP Business Development of the Corporation since August 1, 2018. Prior thereto head of investment banking at AltaCorp Capital Inc. (2011-2018).	August 1, 2018
Trish Olynyk [(1)] Calgary, Alberta	Executive Vice President	Vice President of the Corporation since April 2019. Prior thereto controller of the Corporation (2005-2019).	April 9, 2019
James A. Glessing [(1)] Calgary, Alberta	Chief Financial Officer	Chief Financial Officer of the Corporation since December 2010. Prior thereto CFO & VP Finance of North Peace Energy (2007-2010).	December 1, 2010
Brett Booth (1) Calgary, Alberta	Vice President, Land	Previously VP Land at Prairie Thunder Resources, Banded Peak Energy, Petrus Resources and prior thereto held various other land positions at Bonavista Energy.	July 28, 2021
Gordon A. Bowerman [(2)] 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 [(3)] [(4)] Calgary, Alberta	Director	President of Weir Resource Management Ltd., a private company based in Calgary, since 1981 and President of a private reclamation company since 2000.	November 11, 2003
Frederick (Ted) L. Morton [(2)] Calgary, Alberta	Director	Professor at the University of Calgary (1981-2017); MLA, Foothills-Rocky View (2004-2012); Alberta Cabinet Minister: Sustainable Resources, Finance & Energy (2006-2012); Executive Fellow, School of Public Policy, University of Calgary (2012-present).	February 24, 2014
Neil M. Mackenzie [(3)] [(4)] Calgary, Alberta	Director	Retired Businessman, prior thereto, Vice-President of Blackstone Drilling Fluids Ltd. (2010 – 2018).	February 24, 2014
Dale Miller [(3)] [(4)] Calgary, Alberta	Director	Director of Prairie Provident Resources Ltd and President of Dark Horse Energy Consultants Ltd. Previously the COO of Hillcrest Petroleum Ltd. and former President and COO of Long Run Exploration.	April 29, 2021
Penelope Payne [(2)] Calgary, Alberta	Director	President of Vercatis Consulting Ltd. and has 20 years of financial accounting and reporting experience. Formerly, Chief Financial Officer of Yangarra from 2006-2010.	April 29, 2021

Notes:

(1) Member of the Management Committee
(2) Member of the Audit Committee.
(3) Member of the Reserves Committee
(4) Member of the Corporate Governance, Nominating and 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, 2023, the directors and officers of the Corporation, as a group, beneficially owned or controlled, directly or indirectly, 14,338,093 Common Shares, representing approximately 15% of the issued and outstanding Common Shares as at that date. The directors and executive officers, as a group, also held options to purchase 5,675,340 Common Shares as at December 31, 2023 and 691,500 restricted share units.

The fully diluted holdings of directors and executive officers, as a group were 20,704,933 Common Shares, or approximately 20% of the Common Shares that were outstanding on a fully diluted basis, at December 31, 2023.

Cease Trade Orders

To the knowledge of management of the Corporation, no director or executive officer as at the date hereof, or within 10 years before the date hereof, was a director, chief executive officer or chief financial officer of any company (including the Corporation), that was (a) 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) 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

To the knowledge of management of the Corporation, 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.

To the knowledge of management of the Corporation, 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 (the "**Audit Committee**") is to provide assistance to 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. The Audit Committee's objective is 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, Frederick (Ted) Morton, and Penelope (Penny) Payne (Chair). Each of the members is 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 is currently the President of a private oil and gas company.

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

Penelope (Penny) Payne, CPA, CA – Ms. Payne is currently President of Vercatis Consulting Ltd. and has 20 years of financial accounting and reporting experience. Formerly, she was the Chief Financial Officer of Yangarra from 2006 to 2010. Ms. Payne started her accounting career at PwC Canada and MNP LLP and obtained her CA designation in 1996.

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 Audit Committee to nominate or compensate an external auditor (currently, MNP LLP, Chartered Professional 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, 2023	$157,000(1)	$26,000(3)	$nil	$nil
December 31, 2022	$157,000(2)	$nil	$nil	$nil

Notes:

(1) Includes $42,000 for quarterly reviews.
(2) Includes $42,000 for quarterly reviews.
(3) Fees related to the March 27, 2023, Prospectus

DESCRIPTION OF CAPITAL STRUCTURE

Credit Facility

The Corporation's $135 million syndicated Credit Facility is comprised of a $110 million extendable revolving term credit facility and a $25 million operating facility. The Credit Facility will reduce by $5 million per quarter through to September 30, 2024, at which point the facility will remain at $120 million. The amount available under these facilities is re-determined at least twice a year and is primarily based on the Corporation's oil and gas reserves, the syndicate of lending institutions' forecast commodity prices, the current economic environment and other factors as determined by the syndicate (the "**Borrowing Base**"). If the total advances made under the Credit Facilities are greater than the re-determined Borrowing Base, the Corporation has 60 days to repay any shortfall. The facilities last for a 364-day period and will be subject to the next 364-day extension by May 31, 2024. If not extended by May 31, 2024, the facilities will cease to revolve, and all outstanding balances will become repayable on May 31, 2025.

The Credit Facility bears interest at the banks' prime lending or bankers' acceptance rates plus applicable margins. The applicable margin charged by the bank is dependent upon our debt to earnings before interest, taxes, depreciation and amortization (EBITDA) ratio for the most recent two quarters.

The Corporation is subject to a single financial covenant requiring an adjusted working capital ratio above 1:1 (current assets plus the undrawn availability under the revolving facility, divided by the current liabilities less the drawn portion of the revolving facility and excluding unrealized commodity contracts). The Corporation was in compliance with this covenant as at December 31, 2023 and December 31, 2022. The Credit Facility is secured by a general security agreement over all assets of the Corporation.

Share Capital

The following is a description of the rights, privileges, restrictions and conditions attaching to our share capital.

The Corporation is authorized to issue an unlimited number of Common Shares, without nominal or par value, an unlimited number of First Preferred Shares (the "**First Preferred Shares**"), and an unlimited number of Second Preferred Shares (the "**Second Preferred Shares**", and together with the First Preferred Shares, the "**Preferred Shares**"), both issuable in series. As of the date of this Annual Information Form, 94,800,834 Common Shares and nil Preferred Shares are issued and outstanding.

Common Shares

Holders of Common Shares are entitled to: (a) one vote per 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.

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.

MARKET FOR SECURITIES

Trading Price and Volume

The Common Shares have been listed and posted for trading on the 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**
December 2023	$ 1.40	$ 1.19	2,661,300
November 2023	$ 1.77	$ 1.36	2,061,800
October 2023	$ 1.86	$ 1.64	1,771,400
September 2023	$ 1.98	$ 1.78	1,985,400
August 2023	$ 1.95	$ 1.69	1,222,200
July 2023	$ 1.93	$ 1.63	1,694,700
June 2023	$ 1.73	$ 1.58	1,173,300
May 2023	$ 1.84	$ 1.58	1,830,100
April 2023	$ 1.99	$ 1.75	2,786,900
March 2023	$ 2.41	$ 1.68	8,609,500
February 2023	$ 2.45	$ 2.06	2,647,600
January 2023	$ 2.80	$ 2.31	3,733,800

Prior Sales

The following table summarizes the issuances of Common Shares and securities convertible into Common Shares within the 12-month period ended December 31, 2023.

Date of Issuance	Class of Security	Number or Securities Issued	Issue / Exercise Price
March 27, 2023	Common Shares	6,791,440	$2.54
June 29, 2023	Common Shares	25,000	$1.13

Escrowed Securities

To Yangarra's knowledge, no securities of the Corporation are currently escrowed or subject to a contractual restriction on transfer.

INFORMATION CONCERNING THE OIL AND NATURAL GAS INDUSTRY

The discussion below outlines some of the principal aspects of the legislation, regulations, agreements, orders, directives and a summary of other pertinent conditions that impact the oil and gas industry in Western Canada, where the Corporation's assets are primarily located. While these matters do not affect the Corporation's operations in any manner that is materially different than the manner in which they affect other similarly sized industry participants with similar assets and operations, investors should consider such matters carefully.

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.

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.

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.

Exports from Canada

The Canada Energy Regulator (the "**CER**") regulates the export of oil, natural gas and NGLs from Canada through the issuance of short-term orders and longer-term licences pursuant to its authority under the *Canadian Energy Regulator Act* (the "**CERA**"). Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the CER and the federal government. We do not directly enter into contracts to export our production outside of Canada.

Transportation Constraints and Market Access

Pipelines

Under the Canadian constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and require a regulatory review and approval by Cabinet. However, recent years have seen a perceived lack of policy and regulatory certainty at a federal level. The federal government amended the federal approval process with the CER, which aims to create efficiencies in the project approval process while upholding stringent environmental and regulatory standards. However, as the CER has not yet undertaken a major project approval, it is unclear how the new regulator operates compared to the National Energy Board ("**NEB**") and whether it will result in a more efficient approval process. Lack of regulatory certainty is likely to influence investment decisions for major projects. Even when projects are approved on a federal level, such projects often face further delays due to interference by provincial and municipal governments. Additional delays causing further uncertainty result from legal opposition related to issues such as Indigenous rights and title, the government's duty to consult and accommodate Indigenous peoples, and the sufficiency of all relevant environmental review processes. Export pipelines from Canada to the United States face additional unpredictability as such pipelines require approvals of several levels of government in the United States.

In the face of such regulatory uncertainty, the Canadian crude oil and natural gas industry has experienced significant difficulty expanding the existing network of transportation infrastructure for crude oil, natural gas and NGLs, including pipelines, rail, trucks and marine transport. Improved access to global markets through the Midwest United States and export shipping terminals on the west coast of Canada could help to alleviate downward pressure on commodity prices. Several proposals have been announced to increase pipeline capacity from Western Canada to Eastern Canada, the United States, and other international markets via export terminals. While certain projects are proceeding, the regulatory approval process and other factors related to transportation and export infrastructure have led to the delay, suspension or cancellation of a number of pipeline projects. With respect to the current state of the transportation and exportation of crude oil from Western Canada to domestic and international markets, the Enbridge Line 3 Replacement from Hardisty, Alberta, to Superior, Wisconsin, formerly expected to be in-service in late 2019, continues to experience permitting difficulties in the United States.

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of political opposition in British Columbia, the federal government-owned Trans Mountain Corp. acquired the Trans Mountain Pipeline in August 2018. Following the resolution of various legal challenges and a second regulatory hearing, construction on the Trans Mountain Pipeline expansion commenced in late 2019. Budget increases and in service date delays have been attributed to, among other things, high global inflation, global supply chain challenges, the widespread flooding in British Columbia in late 2021, and unexpected archeological discoveries. On June 1, 2023, Trans Mountain Corp. submitted an application to the CER proposing a base toll of $11-12 per barrel, which was met with great opposition; a multiple stage hearing process is underway, and a decision has not yet been released. The federal government has been in discussions with Indigenous groups and businesses regarding selling significant equity stakes in the pipeline, however no agreements have yet been reached.

In December 2023, the Canada Energy Regulator denied Trans Mountain's pipeline variance application for the Mountain 3 Horizontal Directional Drill (located in the Fraser Valley); however, in January 2024, it approved the request with conditions, meaning the Trans Mountain Pipeline expansion can now proceed toward completion in compliance with the order. The pipeline is expected to be in service in 2024, an extension from the initial December 2022 estimate.

Marine Tankers

The *Oil Tanker Moratorium Act*, which was enacted in June 2019, imposes a ban on tanker traffic transporting crude oil or persistent crude oil products in excess of 12,500 metric tonnes to and from ports located along British Columbia's north coast. The ban may prevent pipelines being built to, and export terminals being located on, the portion of the British Columbia coast subject to the moratorium.

Crude Oil and Bitumen by Rail

On February 19, 2019, the Government of Alberta announced that it would lease 4,400 rail cars capable of transporting 120,000 bbl/d of crude oil out of the province to help alleviate the transportation constraints impacting Canadian oil prices.

In the spring of 2019, the Government of Alberta announced it would cancel the program and assign the transportation contracts to industry proponents. In February 2020, the Government of Alberta announced it had sold $10.6 billion worth of crude-by-rail contracts to the private sector.

Following two train derailments that led to fires and oil spills in Saskatchewan, the federal government announced in February 2020, that trains hauling more than 20 cars carrying dangerous goods, including crude oil and diluted bitumen, would be subject to reduced speed limits. The order was updated in early April 2020 and will remain in place until permanent rule changes are approved. As a result, trains subject to the order will be required to adhere to the reduced speed limits announced in February 2020 within metropolitan areas, with further mandatory speed reductions applying outside of metropolitan areas during winter months (November 15 to March 15).

Natural Gas and LNG

Natural gas prices in Alberta have also been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. Companies that secure firm access to transport their natural gas production out of Western Canada may be able to access more markets and obtain better pricing. Companies without firm access may be forced to accept spot pricing in Western Canada for their natural gas, which in the last several years has generally been depressed (at times producers have received negative pricing for their natural gas production).

Required repairs or upgrades to existing pipeline systems in Western Canada have also led to reduced capacity and apportionment of access, the effects of which have been exacerbated by storage limitations. In October 2020, TC Energy Corporation received federal approval to expand the Nova Gas Transmission Line system (the "**NGTL System**"). The NGTL System is in the midst of implementing a $6.5 billion infrastructure program, which added 1.3 billion cubic feet per day of capacity in 2022, and an additional 2.2 billion cubic feet per day of capacity is planned between 2023 and 2026.

There are currently eight LNG export projects at different stages of development across the country with most being located in British Columbia. LNG Canada's LNG liquefaction facility and export terminal in Kitimat, British Columbia will be Canada's first operational large-scale LNG export facility. Once complete, producers in northeastern British Columbia will be able to transport natural gas to the facility via the Coastal GasLink pipeline (the "**CGL Pipeline**"). The LNG Canada facility is more than 85% complete, and the CGL Pipeline is now mechanically complete. The facility will launch its startup program in 2024 to test and fine tune equipment, which will take over a year to complete, before becoming fully operational. The Woodfibre LNG project is located near Squamish, British Columbia, and upon completion will produce approximately 2.1 million tonnes of LNG per year. Construction began in the fall of 2023 and substantial completion of the project is expected in late 2027. Most of the other project's target becoming operational between 2027 and 2030, although there is no guarantee that all or any of these projects will proceed.

International Trade Agreements

NAFTA/USMCA

The *North American Free Trade Agreement* ("**NAFTA**") that previously existed among the governments of Canada, the United States and Mexico has been replaced by a new trade agreement, widely referred to as the United States Mexico Canada Agreement (the "**USMCA**") and sometimes referred to as the Canada United States Mexico Agreement (CUSMA). The USMCA came into force on July 1, 2020. Because the United States remains Canada's primary trading partner and the largest international market for the export of crude oil, natural gas, and NGL from Canada, the implementation of the USMCA could have an impact on Western Canada's petroleum and natural gas industry at large, including the Company's business.

While the proportionality rules in Article 605 of NAFTA previously prevented Canada from implementing policies that limit exports to the United States and Mexico relative to the total supply produced in Canada, the USMCA does not contain the same proportionality requirements. This may allow Canadian producers to develop a more diversified export portfolio than was possible under NAFTA, subject to the construction of infrastructure allowing more Canadian production to reach other international markets.

Other Trade Agreements

Canada has also pursued a number of other international free trade agreements with other countries around the world and, as a result, a number of free trade or similar agreements are in force between Canada and certain other countries. Canada and the European Union recently agreed to the *Comprehensive Economic and Trade Agreement* ("**CETA**"), which provides for duty-free, quota-free market access for Canadian crude oil and natural gas products to the European Union. Although CETA has not received full ratification by national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017. In light of the United Kingdom's departure from the European Union (Brexit) on January 31, 2020, the United Kingdom and Canada have reached an interim post-Brexit trade agreement, the *Canada-United Kingdom Trade Continuity Agreement* ("**CUKTCA**"). On December 9, 2020, the Government of Canada introduced Bill C-18, an Act to Implement the Trade Continuity Agreement. CETA ceased to apply to Canada-United Kingdom trade on January 1, 2021, and CUKTCA came into force on April 1, 2021. The CUKTCA replicates CETA on a bilateral basis and is meant to maintain the status quo of the Canada-United Kingdom trade relationship.

Canada and 10 other countries signed the Comprehensive and Progressive Agreement for Trans-Pacific Partnership (the "**CPTPP**") on March 8, 2018, which is intended to allow for preferential market access among the countries that are parties to the CPTPP. The CPTPP is in force among: Canada, Australia, Japan, Mexico, New Zealand, Singapore, Vietnam, Peru, Malaysia, Chile and Brunei Durussalam. As other countries ratify the agreement, they are added to the annexes. The CPTPP facilitates temporary entry to Canada for certain categories of businesspersons who are citizens of other countries which are signatories to the CPTPP.

In August 2023, an updated version of the *Canadian Free Trade Agreement* (the "**CFTA**") was published, aiming to revamp the Agreement on International Trade to create a more robust and equitable trade environment within Canada. While it is uncertain what effect CETA, CPTPP, CUKTCA, CFTA or any other trade agreements will have on the petroleum and natural gas industry in Canada, the lack of available infrastructure for the offshore export of crude oil and natural gas may limit the ability of Canadian crude oil and natural gas producers to benefit from such trade agreements.

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 shutdowns 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 NEB approval for large projects. This may cause the timeframe for project approvals for current and future applications to increase.

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.

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.

Occasionally, both the federal government and the provincial governments in Western Canada create incentive programs for the oil and gas industry. These programs often provide for volume-based incentives, royalty rate reductions, royalty holidays or royalty tax credits and may be introduced when commodity prices are low to encourage exploration and development activity. Governments may also introduce incentive programs to encourage producers to prioritize certain kinds of development or utilize technologies that may enhance or improve recovery of oil, natural gas and NGLs, or improve environmental performance. In addition, from time to time, including during the COVID-19 pandemic, the federal government creates incentives and other financial aid programs intended to assist businesses operating in the oil and gas industry and other industries in Canada.

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 AER on an annual basis.

Producers pay a flat royalty rate of 5% 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.

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 4% of revenues reported from fee simple mineral title properties.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. For example, the Innovative Energy Technologies Program (the "**IETP**"), 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

The new Enhanced Hydrocarbon Recovery Program (the "**EHR Program**") began January 1, 2017, and replaced the previous royalty framework. 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% 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% 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. In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and GHG emissions including carbon dioxide equivalents ("**CO2e**"), may impose further requirements on operators and other companies in the crude oil and natural gas industry.

Federal

Canadian environmental regulation is the responsibility of both the federal and provincial governments. While provincial governments and their delegates are responsible for most environmental regulation, the federal government can regulate environmental matters where they impact matters of federal jurisdiction or when they arise from projects that are subject to federal jurisdiction, such as interprovincial transportation undertakings, including pipelines and railways, and activities carried out on federal lands. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law prevails.

The CERA and the *Impact Assessment Act* (the "**IAA**") provide a number of important elements to the regulation of federally regulated major projects and their associated environmental assessments. The CERA separates the CER's administrative and adjudicative functions. The CER has jurisdiction over matters such as the environmental and economic regulation of pipelines, transmission infrastructure and certain offshore renewable energy projects. In its adjudicative role, the CERA tasks the CER with reviewing applications for the development, construction and operation of many of these projects, culminating in their eventual abandonment.

The IAA relies on a designated project list as a trigger for a federal assessment. Designated projects that may have effects on matters within federal jurisdiction will generally require an impact assessment administered by the Impact Assessment Agency (the "**IA Agency**") or, in the case of certain pipelines, a joint review panel comprised of members from the CER and the IA Agency. The impact assessment requires consideration of the project's potential adverse effects and the overall societal impact that a project may have, both of which may include a consideration of, among other items, environmental, biophysical and socio-economic factors, climate change, and impacts to Indigenous rights. It also requires an expanded public interest assessment. Designated projects specific to the oil and gas industry include pipelines that require more than 75km of new rights of way and pipelines located in national parks, large scale in situ oil sands projects not regulated by provincial GHG emissions caps and certain refining, processing and storage facilities.

The federal government has stated that an objective of the legislative changes was to improve decision certainty and turnaround times. Once a review or assessment is commenced under either the CERA or IAA, there are limits on the amount of time the relevant regulatory authority will have to issue its report and recommendation. Designated projects will go through a planning phase to determine the scope of the impact assessment, which the federal government has stated should provide more certainty as to the length of the full review process.

In May 2022, the Alberta Court of Appeal released its decision in response to the Government of Alberta's submission of a reference question regarding the constitutionality of the IAA. The Court found the IAA to be unconstitutional in its entirety, stating that the legislation effectively granted the federal government a veto over projects that were wholly within provincial jurisdiction. Shortly after the decision was released, the Government of Canada announced its intention to appeal the decision to the Supreme Court of Canada.

Alberta

The AER is the principal regulator responsible for all energy resource development in Alberta. It derives its authority from the Responsible Energy Development Act and a number of related statutes including the *Oil and Gas Conservation Act* (the "**OGCA**"), the *Oil Sands Conservation Act*, the *Pipeline Act*, and the *Environmental Protection and Enhancement Act*. The AER is responsible for ensuring the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources, including allocating and conserving water resources, managing public lands, and protecting the environment. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as the Alberta Ministry of Energy's responsibility for mineral tenure.

The Government of Alberta relies on regional planning to accomplish its resource development goals. Its approach to natural resource management provides for engagement and consultation with stakeholders and the public and examines the cumulative impacts of development on the environment and communities. While the AER is the primary regulator for energy development, several other governmental departments and agencies may be involved in land use issues, including the Alberta Ministry of Environment and Parks, the Alberta Ministry of Energy, the Aboriginal Consultation Office and the Land Use Secretariat.

The Government of Alberta's land-use policy sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of seven region-specific land-use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans.

The AER monitors seismic activity across Alberta to assess the risks associated with, and instances of, earthquakes induced by hydraulic fracturing. Hydraulic fracturing involves the injection of water, sand or other proppants and additives under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate oil and natural gas production. We routinely conduct hydraulic fracturing in our drilling and completion programs. In recent years, hydraulic fracturing has been linked to increased seismicity in the areas in which hydraulic fracturing takes place, prompting regulatory authorities to investigate the practice further.

The AER has developed monitoring and reporting requirements that apply to all oil and natural gas producers working in certain areas where the likelihood of an earthquake is higher, and implemented the requirements in Subsurface Order Nos. 2, 6, and 7. The regions with seismic protocols in place are Fox Creek, Red Deer, and Brazeau (the "**Seismic Protocol Regions**") We do have operations in Brazeau. Oil and natural gas producers in each of the Seismic Protocol Regions are subject to a "traffic light" reporting system that sets thresholds on the Richter scale of earthquake magnitude. The thresholds vary among the Seismic Protocol Regions and trigger a sliding scale of obligations from the oil or natural gas producers operating there. Such obligations range from no action required, to informing the AER and invoking an approved response plan, to ceasing operations and informing the AER. The AER has the discretion to suspend operations while it investigates following a seismic event until it has assessed the ongoing risk of earthquakes in a specific area and/or may require the operator to update its response plan. The AER may extend these requirements to other areas of Alberta if necessary, subject to the results of its ongoing province-wide monitoring.

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.

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

Our exploration and production facilities and other operations and activities emit GHGs which may require us to comply with federal and/or provincial GHG emissions legislation. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place to prevent climate change or mitigate our effects. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. Some of our significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions.

Climate change has been linked to long-term shifts in climate patterns, including sustained higher temperatures. As the level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns, long-term shifts in climate patterns pose the risk of exacerbating operational delays and other risks posed by seasonal weather patterns. In addition, long-term shifts in weather patterns such as water scarcity, increased frequency of storm and fire and prolonged heat waves may, among other things, require us to incur greater expenditures (time and capital) to deal with the challenges posed by such changes to our premises, operations, supply chain, transport needs, and employee safety. Specifically, in the event of water shortages or sourcing issues, we may not be able to, or will incur greater costs to, carry out hydraulic fracturing operations.

Concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of hydrocarbons which has influenced investors' willingness to invest in the oil and natural gas industry. Historically, political and legal opposition to the hydrocarbon industry focused on public opinion and the regulatory process. More recently, however, there has been a movement to more directly hold governments and oil and natural gas companies responsible for climate change through climate litigation. In recent years, climate change advocacy groups have attempted to bring legal action against various levels of government for climate-related harms.

Given the evolving nature of climate change policy and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing our operating expenses, and, in the long-term, potentially reducing the demand for oil and natural gas production, resulting in a decrease in our profitability and a reduction in the value of our assets or requiring asset impairments for financial statement purposes. See "*Information Concerning the Oil and Natural Gas Industry – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*", "*Risk Factors – Non-Governmental Organizations*", "*Risk Factors – Reputational Risk Associated with our Operations*" and "*Risk Factors – Changing Investor Sentiment*".

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") since 1992. Since its inception, the UNFCCC has instigated numerous policy changes with respect to climate governance. On April 22, 2016, 197 countries, including Canada, signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. To date, 189 of the 197 parties to the UNFCCC have ratified the Paris Agreement, including Canada. In 2016, Canada committed to reducing its emissions by 30% below 2005 levels by 2030. In 2021, Canada updated its original commitment by pledging to reduce emissions by 40–45% below 2005 levels by 2030, and to net-zero by 2050.

During the 2021 United Nations Climate Change Conference, Canada pledged to (i) reduce methane emissions in the oil and gas sector to 75% of 2012 levels by 2030; (ii) cease to export thermal coal by 2030; (iii) impose a cap on emissions from the oil and gas sector; (iv) halt direct public funding to the global fossil fuel sector by the end of 2022; and (v) commit that all new vehicles sold in the country will be zero-emission on or before 2040. During the 2023 United Nations Climate Change Conference, Canada signed an agreement with nearly 200 other parties, which includes renewed commitments to transitioning away from fossil fuels and further cutting GHG emissions.

In 2022, the federal government published a discussion paper that outlined two potential regulatory options for capping emissions from the oil and gas sector: (i) to implement a new cap-and-trade system that would set a limit on emissions from the sector; or (ii) to modify the existing pollution pricing benchmark (as discussed below) to limit emissions from the sector. The federal government has completed its formal engagement on potential regulatory options to cap emissions and released the proposed regulatory framework on December 7, 2023, which is discussed in more detail below.

The Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change in 2016, setting out a plan to meet the federal government's 2030 emissions reduction targets. On June 21, 2018, the federal government enacted the Greenhouse Gas Pollution Pricing Act (the "**GGPPA**"), which came into force on January 1, 2019. This regime has two parts: an output-based pricing system ("**OBPS**") for large industry (enabled by the Output-Based Pricing System Regulations) and a fuel charge (enabled by the Fuel Charge Regulations), both of which impose a price on CO2e emissions. The GGPPA system applies in provinces and territories that request it and in those that do not have their own equivalent emissions pricing systems in place that meet the federal standards and ensure that there is a uniform price on emissions across the country.

Originally under the federal plans, the price was set to escalate by $10 per year until it reached a maximum price of $50/tonne of CO2e in 2022. However, on December 11, 2020, the federal government announced its intention to continue the annual price increases beyond 2022. Commencing in 2023, the benchmark price per tonne of CO2e increases by $15 per year until it reaches $170/tonne of CO2e in 2030 (currently $80/tonne). While several provinces challenged the constitutionality of the GGPPA following its enactment, the Supreme Court of Canada confirmed its constitutional validity in a judgment released on March 25, 2021.

On April 26, 2018, the federal government passed the Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) (the "**Federal Methane Regulations**"). The Federal Methane Regulations seek to reduce emissions of methane from the oil and natural gas sector, and came into force on January 1, 2020. By introducing new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and the intentional venting of methane and ensure that oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and natural gas facilities are permitted to vent. The regulations aim to reduce the oil and gas sector's methane emissions by 40–45% by 2025, relative to 2012 emissions.

In December 2023, the federal government released proposed amendments to the Federal Methane Regulations in order to further reduce upstream methane emissions and to contribute to Canada meeting its international climate-related commitments. The proposed amendments would build on the existing requirements and increase stringency by introducing new prohibitions and limits on certain intentional emissions, a new risk-based approach around unintentional emissions, and a new performance-based approach for compliance that relies on continuous emissions monitoring systems, among other things. The proposed amendments are targeted to come into force in January 2027.

The federal government has enacted the Multi-Sector Air Pollutants Regulation under the authority of the Canadian Environmental Protection Act, 1999, which regulates certain industrial facilities and equipment types, including boilers and heaters used in the upstream oil and gas industry, to limit the emission of air pollutants such as nitrogen oxides and sulphur dioxide.

The Canadian Net-Zero Emissions Accountability Act (the "**CNEAA**") received royal assent on June 29, 2021, and came into force on the same day. The CNEAA binds the Government of Canada to a process intended to help Canada achieve net-zero emissions by 2050. It establishes rolling five-year emissions reduction targets and requires the government to develop plans to reach each target and support these efforts by creating a Net-Zero Advisory Body. The CNEAA also requires the federal government to publish annual reports that describe how departments and Crown corporations are considering the financial risks and opportunities of climate change in their decision-making. A comprehensive review of the CNEAA is required every five years from the date the CNEAA came into force.

The Government of Canada introduced its 2030 Emissions Reduction Plan (the "**2030 ERP**") on March 29, 2022. In the 2030 ERP, the Government of Canada proposes a roadmap to reduce its GHG emissions to 40-45% below 2005 levels by 2030. As the first emissions reduction plan issued under the CNEAA, the 2030 ERP aims to reduce emissions by incentivizing electric vehicles and renewable electricity, and capping emissions from the oil and gas sector, among other measures.

On June 8, 2022, the Canadian Greenhouse Gas Offset Credit System Regulations were published in the Canada Gazette. The regulations establish a regulatory framework to allow certain kinds of projects to generate and sell offset credits for use in the federal OBPS through Canada's Greenhouse Gas Offset Credit System. The system enables project proponents to generate federal offset credits through projects that reduce GHG emissions under a published federal GHG offset protocol. Offset credits can then be sold to those seeking to meet limits imposed under the OBPS or those seeking to meet voluntary targets.

On June 20, 2022, the federal Clean Fuel Regulations came into force and in July 2023 they took effect. The Clean Fuel Regulations aim to discourage the use of fossil fuels by increasing the price of those fuels when compared to lower-carbon alternatives, imposing obligations on primary suppliers of transportation fuels in Canada, and requiring fuels to contain a minimum percentage of renewable fuel content and meet emissions caps calculated over the life cycle of the fuel. The Clean Fuel Regulations also establish a market for compliance credits. Compliance credits can be generated by primary suppliers, among others, through carbon capture and storage, producing or importing low-emission fuel, or through end-use fuel switching (for example, operating an electric vehicle charging network).

Additionally, on December 7, 2023, the Minister of Environment and Climate Change and the Minister of Energy and Natural Resources, introduced Canada's draft cap-and-trade framework to limit emissions from the oil and gas sector. The proposed Regulatory Framework for an Oil and Gas Sector Greenhouse Gas Emissions Cap proposes capping 2030 emissions at 35 to 38 percent below 2019 levels, while providing certain flexibilities to emit up to a level around 20 to 23 percent below 2019 levels. The purpose of the proposed cap is to ensure that Canada is on track to meet its target of achieving net-zero by 2050. It is expected that the regulations will be finalized and released sometime in 2025 with annual reporting required as early as 2026 and a phasing in period taking place between 2026 and 2030.

The Government of Canada is also in the midst of developing a carbon capture utilization and storage ("**CCUS**") strategy. CCUS is a technology that captures carbon dioxide from facilities, including industrial or power applications, or directly from the atmosphere. The captured carbon dioxide is then compressed and transported for permanent storage in underground geological formations or used to make new products such as concrete. As part of the 2021 budget, the federal government committed to investing $319 million over seven years to ramp up CCUS in Canada, as this will be a critical element of the plan to reach net-zero by 2050. The House of Commons is currently considering legislation pursuant to which it will start paying subsidies for carbon capture and net-zero energy projects; an update is expected in early 2024.

In June 2023, the IFRS issued two international reporting standards on sustainability: IFRS S1, which addresses sustainability-related disclosure, and IFRS S2, which addresses climate-related disclosure. The new standards require issuers, among other things, to include quantitative data regarding their climate change considerations, to use scenario analysis in developing their disclosure, and to disclose Scope 3 GHG emissions. While Canadian companies are not required to follow IFRS S1 and IFRSS2 at this time, the Canadian Securities Administrators is considering amending Canadian reporting requirements to include the new international standards, however to what extent they will be adopted remains unclear.

Alberta

In December 2016, the *Oil Sands Emissions Limit Act* came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, but the regulations necessary to enforce the limit have not yet been developed. The delay in drafting these regulations has been inconsequential thus far, as Alberta's oil sands emit roughly 70 megatonnes of GHG emissions per year, well below the 100 megatonne limit.

In June 2019, the fuel charge element of the federal backstop program took effect in Alberta. The carbon tax payable in Alberta will continue to increase at a rate of $15 per year until it reaches $170 per tonne in 2030 (currently $80/tonne). In December 2019, the federal government approved Alberta's Technology Innovation and Emissions Reduction ("**TIER**") regulation, which applies to large emitters. The TIER regulation came into effect on January 1, 2020 (as amended on January 1, 2023) and replaced the previous Carbon Competitiveness Incentives Regulation. The TIER regulation meets the federal benchmark stringency requirements for emissions sources covered in the regulation, and the federal backstop continues to apply to emissions sources not covered by the regulation.

The governments of British Columbia, Alberta and Saskatchewan enacted provincial regulations designed to lower annual methane emissions from the oil and gas sector 45% by 2025, in line with the federal methane regulations and effective January 1, 2020. The Government of Canada announced equivalency agreements with each province regarding the regulation of methane emissions from the oil and gas sector such that the federal methane regulations would not apply in these jurisdictions.

Liability Management

The AER administers the Liability Management Framework (the "**AB LM Framework**") and the Liability Management Rating Program (the "**AB LMR Program**") to manage liability for most conventional upstream oil and natural gas wells, facilities and pipelines in Alberta. The AER is in the process of replacing the AB LMR Program with the AB LM Framework. Broadly, the AB LM Framework is intended to provide a more holistic approach to liability management in Alberta, as the AER found that the more formulaic approach under the AB LMR Program did not necessarily indicate whether a company could meet its liability obligations. New developments under the AB LM Framework include a new Licensee Capability Assessment System (the "**AB LCA**"), a new Inventory Reduction Program (the "**AB IR Program**"), and a new Licensee Management Program ("**AB LM Program**"). Meanwhile, some programs under the AB LMR Program remain in effect, including the Oilfield Waste Liability Program (the "**AB OWL Program**"), the Large Facility Liability Management Program (the "**AB LF Program**") and elements of the Licensee Liability Rating Program (the "**AB LLR Program**"). The mix between active programs under the AB LM Framework and the AB LMR Program highlights the transitional and dynamic nature of liability management in Alberta. While the province is moving towards the AB LM Framework and a more holistic approach to liability management, the AER has noted that this will be a gradual process that will take time to complete. In the meantime, the AB LMR Program continues to play an important role in Alberta's liability management scheme.

Complementing the AB LM Framework and the AB LMR Program, Alberta's OGCA establishes an orphan fund (the "**Orphan Fund**") to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program and the AB OWL Program if a licensee or working interest participant becomes insolvent or is unable to meet its obligations. Licensees in the AB LLR Program and the AB OWL Program fund the Orphan Fund through a levy administered by the AER. However, given the increase in orphaned oil and natural gas assets, the Government of Alberta has loaned the Orphan Fund approximately $335 million to carry out abandonment and reclamation work. In response to the COVID-19 pandemic, the Government of Alberta also covered $113 million in levy payments that licensees would otherwise have owed to the Orphan Fund, corresponding to the levy payments due for the first six months of the AER's fiscal year. A separate orphan levy applies to persons holding licences subject to the AB LF Program. Collectively, these programs are designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines.

The Supreme Court of Canada's decision in *Orphan Well Association v Grant Thornton* (also known as the "**Redwater Decision**"), provides the backdrop for Alberta's approach to liability management. As a result of the Redwater Decision, receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a licence transfer when any such licensee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets that have reached the end of their productive lives (and therefore represent a net liability) in order to deal primarily with the remaining productive and valuable assets without first satisfying any abandonment and reclamation obligations associated with the insolvent estate's assets. In April 2020, the Government of Alberta passed the *Liabilities Management Statutes Amendment Act*, which places the burden of a defunct licensee's abandonment and reclamation obligations first on the defunct licensee's working interest partners, and second, the AER may order the Orphan Fund to assume care and custody and accelerate the clean-up of wells or sites which do not have a responsible owner. These changes came into force in June 2020.

One important step in the shift to the AB LM Framework has been amendments to Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals ("**Directive 067**"), which deals with licensee eligibility to operate wells and facilities. All licence transfers and granting of new well, facility and pipeline licences in Alberta are subject to AER approval. Previously under the AB LMR Program, as a condition of transferring existing AER licences, approvals and permits, all transfers required transferees to demonstrate that they had a liability management rating of 2.0 or higher immediately following the transfer. If transferees did not have the required rating, they would have to otherwise prove to the satisfaction of the AER that they could meet their abandonment and reclamation obligations, through means such as posting security or reducing their existing obligations. However, amendments from April 2021 to Directive 067 expanded the criteria for assessing licensee eligibility. Notably, the recent amendments increase requirements for financial disclosure, detail new requirements for when a licensee poses an "unreasonable risk" of orphaning assets, and adds additional general requirements for maintaining eligibility.

Alongside changes to Directive 067, the AER also introduced Directive 088: Licensee Life-Cycle Management ("**Directive 088**") in December 2021 under the AB LM Framework. Directive 088 replaces, to an extent, the AB LLR Program with the AB LCA. Whereas the AB LLR Program previously assessed a licensee based on a liability rating determined by the ratio of a licensee's deemed asset value relative to the deemed liability value of its oil and gas wells and facilities, the AB LCA now considers a wider variety of factors and is intended to be a more comprehensive assessment of corporate health. Such factors are wide reaching and include: (i) a licensee's financial health; (ii) its established total magnitude of liabilities; (iii) the remaining lifespan of its mineral resources; (iv) the management of its operations; (v) the rate of closure activities for its liabilities; and (vi) and its compliance with administrative and regulatory requirements. These various factors then feed into a broader holistic assessment of a licensee under the AB LM Framework. In turn, that holistic assessment provides the basis for assessing risk posed by licence transfers, as well as any security deposit that the AER may require from a licensee in the event that the regulator deems a licensee at risk of not being able to meet its liability obligations. However, the liability management rating under the LLR Program is still in effect for other liability management programs such as the AB OWL Program and the AB LF Program, and will remain in effect until a broadened scope of Directive 088 is phased in over time.

In addition to the AB LCA, Directive 088 also implemented other new liability management programs under the AB LM Framework. These include the AB LM Program and the AB IR Program. Under the AB LM Program, the AER will continuously monitor licensees over the life-cycle of a project. If, under the AB LM Program, the AER identifies a licensee as high risk, the regulator may employ various tools to ensure that a licensee meets its regulatory and liability obligations. In addition, under the AB IR Program the AER sets industry wide spending targets for abandonment and reclamation activities. Licensees are then assigned a mandatory licensee specific target based on the licensee's proportion of provincial inactive liabilities and the licensee's level of financial distress. Certain licensees may also elect to provide the AER with a security deposit in place of their closure spend target.

The Government of Alberta followed the announcement of the AB LM Framework with amendments to the Oil and Gas Conservation Rules and the Pipeline Rules in late 2020. The changes to these rules fall into three principal categories: (i) they introduce "closure" as a defined term, which captures both abandonment and reclamation; (ii) they expand the AER's authority to initiate and supervise closure; and (iii) they permit qualifying third parties on whose property wells or facilities are located to request that licensees prepare a closure plan.

Indigenous Rights

Constitutionally mandated government-led consultation with and, if applicable, accommodation of, the rights of Indigenous groups impacted by regulated industrial activity, as well as proponent-led consultation and accommodation or benefit sharing initiatives, play an increasingly important role in the Western Canadian oil and gas industry. In addition, Canada is a signatory to the UNDRIP, and the principles set forth therein may continue to influence the role of Indigenous engagement in the development of the oil and gas industry in Western Canada. For example, in November 2019, the *Declaration on the Rights of Indigenous Peoples Act* ("**DRIPA**") became law in British Columbia. The DRIPA aims to align British Columbia's laws with UNDRIP. In June 2021, the *United Nations Declaration on the Rights of Indigenous Peoples Act* ("**UNDRIP Act**") came into force in Canada. Similar to British Columbia's DRIPA, the UNDRIP Act requires the Government of Canada to take all measures necessary to ensure the laws of Canada are consistent with the principles of UNDRIP and to implement an action plan to address UNDRIP's objectives.

On June 21, 2022, the Minister of Justice and Attorney General issued the First Annual Progress Report on the implementation of the UNDRIP Act (the "**Progress Report**"). The Progress Report provides that, as of June 2022, the federal government has sought to implement the UNDRIP Act by, among other things, creating a Secretariat within the Department of Justice to support Indigenous participation in the implementation of UNDRIP, consulting with Indigenous peoples to identify their priorities, drafting an action plan to align federal laws with UNDRIP, and implementing efforts to educate federal departments on UNDRIP's principles.

Continued development of common law precedent regarding existing laws relating to Indigenous consultation and accommodation as well as the adoption of new laws such as DRIPA and UNDRIP Act are expected to continue to add uncertainty to the ability of entities operating in the Canadian oil and gas industry to execute on major resource development and infrastructure projects, including, among other projects, pipelines. The Government of Canada has expressed that implementation of the UNDRIP Act has the potential to make meaningful change in how Indigenous peoples collaborate in impact assessment moving forward, but has confirmed that the current IAA already establishes a framework that aligns with UNDRIP and does not need to be changed in light of the UNDRIP Act.

On June 29, 2021, the British Columbia Supreme Court issued a judgement in *Yahey v British Columbia* (the "**Blueberry Decision**"), in which it determined that the cumulative impacts of industrial development on the traditional territory of the Blueberry River First Nation ("**BRFN**") in northeast British Columbia had breached the BRFN's rights guaranteed under Treaty 8. Going forward, the Blueberry Decision may lead to similar claims of cumulative effects across Canada in other areas covered by numbered treaties. The long-term impacts and risks of the Blueberry Decision and the election of a new BRFN Chief on the Canadian oil and gas industry remain uncertain.

On January 18, 2023, the Government of British Columbia and the BRFN signed the Blueberry River First Nations Implementation Agreement (the "**BRFN Agreement**"). The BRFN Agreement aims to address the cumulative effects of development on BRFN's claim area through restoration work, establishment of areas protected from industrial development, and a constraint on development activities. Such measures will remain in place while a long-term cumulative effects management regime is implemented. Specifically, the BRFN Agreement includes, among other measures, the establishment of a $200-million restoration fund by June 2025, an ecosystem-based management approach for future land-use planning in culturally important areas, limits on new petroleum and natural gas development, and a new planning regime for future oil and gas activities. The BRFN will receive $87.5 million over three years, with an opportunity for increased benefits based on petroleum and natural gas revenue sharing and provincial royalty revenue sharing in the next two fiscal years.

The BRFN Agreement has acted as a blueprint for other agreements between the Government of British Columbia and Indigenous groups in Treaty 8 territory. In late January 2023, the Government of British Columbia and four Treaty 8 First Nations – Fort Nelson, Salteau, Halfway River and Doig River First Nations – reached consensus on a collaborative approach to land and resource planning (the "**Consensus Agreement**"). The Consensus Agreement implements various initiatives including a "cumulative effects" management system linked to natural resource landscape planning and restoration initiatives, new land-use plans and protection measures, and a new revenue-sharing approach to support the priorities of Treaty 8 First Nations communities.

In July 2022, Duncan's First Nation filed a lawsuit against the Government of Alberta relying on similar arguments to those advanced successfully by the BRFN. Duncan's First Nation claims in its lawsuit that Alberta has failed to uphold its treaty obligations by authorizing development without considering the cumulative impacts on the First Nation's treaty rights. The long-term impacts of the Blueberry Decision and the Duncan's First Nation lawsuit on the Canadian oil and gas industry remain uncertain.

Changing Investor Sentiment

A number of factors, including the effects of the use of hydrocarbons on climate change, the impact of oil and natural gas operations on the environment, environmental damage relating to spills of petroleum products during production and transportation and Indigenous rights, have affected certain investors' sentiments towards investing in the oil and natural gas industry. As a result of these concerns, some institutional, retail and governmental investors have announced that they no longer are willing to fund or invest in oil and natural gas properties or companies, or are reducing the amount thereof over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices. Developing and implementing such policies and practices can involve significant costs and require a significant time commitment from our Board of Directors, management and employees.

Failing to implement the policies and practices, as requested by institutional investors, may result in such investors reducing their investment in us, or not investing in us at all. Any reduction in the investor base interested or willing to invest in the oil and natural gas industry and more specifically, us, may result in limiting our access to capital, increasing the cost of capital, and decreasing the price and liquidity of our Common Shares even if our operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause a decrease in the value of our assets which may result in an impairment change.

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

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% 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.

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 2023 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 2023 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.sedarplus.ca. 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 March 13, 2023. Additional financial information is also provided in the Corporation's consolidated financial statements and MD&A for the year ended December 31, 2023.

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, 2023. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2023, estimated using forecast prices and costs.

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

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "**COGE Handbook**") maintained by the Petroleum Evaluation Engineers (Calgary Chapter).

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

5. The following table 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, 2023, 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 ($MM, before income taxes, 10% discount rate)			
			Audited	**Evaluated**	**Reviewed**	**Total**
Deloitte LLP	December 31, 2023	Canada	**-**	**$1,592.4**	**-**	**$1,592.4**

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

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

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

Executed as to our report referred to above:

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

(signed) "Andrew Botterill"
Andrew Botterill, P. Eng.
Partner

Execution date: February 23, 2024

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, 2023, 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"	*(signed) "James Glessing"*
James Evaskevich	James Glessing
President and CEO	CFO
(signed) "Robert Weir"	*(signed) "Dale Miller"*
Robert Weir	Dale Miller
Director	Director

February 23, 2024

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.