LYCOS ENERGY INC.
ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2022

Dated April 27, 2023

TABLE OF CONTENTS

GLOSSARY

Certain terms and abbreviations used in this annual information form are defined below:

"**Abandonment**" means forecasted abandonment and site reclamation costs. For more detail, please see "*Other Oil and Gas Information – Additional Information concerning Abandonment and Reclamation Costs*".

"**ABCA**" means the *Business Corporations Act* (Alberta), as amended from time to time.

"**AcquisitionCo**" means 2156735 Alberta Ltd., a corporation formed under the laws of the Province of Alberta in connection with the Business Combination, and a wholly owned subsidiary of the Corporation.

"**AIF**" means this annual information form dated April 27, 2023, for the financial year ended December 31, 2022.

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

"**Business Combination**" has the meaning ascribed thereto under "*Corporate Structure*".

"**Business Combination Agreement**" has the meaning ascribed thereto under "*Corporate Structure*".

"**Chronos**" means Chronos Resources Ltd., a corporation formed pursuant to the laws of the Province of Alberta.

"**Chronos Financings**" means the Subscription Receipt Private Placement and the Unit Private Placement, as further described under "*General Development of the Business – Three-Year History – Financial Year Ended December 31, 2022*".

"**Chronos Shares**" means the common shares in the capital of Chronos.

"**Chronos Warrants**" means the Chronos Share purchase warrants issued under each Unit, as further described under "*General Development of the Business – Three-Year History – Financial Year Ended December 31, 2022*".

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly 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.

"**Consolidation**" has the meaning ascribed thereto in "*Note on Common Share Consolidation*".

"**Exchange Ratio**" has the meaning ascribed thereto in "*General Development of the Business – Three-Year History – Financial Year Ended December 31, 2022*".

"**GHG**" means greenhouse gas.

"**GORR**" means gross overriding royalty.

"**IFRS**" means the International Financial Reporting Standards.

"**JV Acquisition**" means the Corporation's acquisition on February 28, 2023 of its joint venture partner's equity interest in the Partnership, as further described under "*General Development of the Business – Recent Developments*".

"**KPMG**" means KPMG LLP, the Corporation's auditors.

"**Lycos**" or the "**Corporation**" means Lycos Energy Inc. (previously named "Samoth Oilfield Inc."), a corporation formed pursuant to the laws of the Province of Alberta.

"**Market Price**" has the meaning ascribed thereto in "*General Development of the Business – Three-Year History – Financial Year Ended December 31, 2022*".

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

"**NI 51-102**" means National Instrument 51-102 – *Continuous Disclosure Obligations*.

"**OPEC**" means the Organization of Petroleum Exporting Countries, and "**OPEC+**" refers to OPEC plus Russia, Azerbaijan, Bahrain, Brunei, Kazakhstan, Malaysia, Mexico, Oman, South Sudan and Sudan.

"**Partnership**" means Chronos Duvernay Limited Partnership.

"**Partnership Assets**" means the assets held by the Partnership, as further described under "*Description of the Business of the Corporation – Description of Principal Properties – Partnership Properties*".

"**Reserves Data**" has the meaning ascribed thereto in "*Statement of Reserves Data and Other Oil and Gas Information – Reserves Data (Forecast Prices and Costs)*".

"**Reserves Report**" means the report prepared by Sproule, evaluating the Crude Oil, natural gas and natural gas liquids reserves of the Corporation, as at December 31, 2022, with a preparation date of March 14, 2023.

"**Shareholders**" means the holders of Common Shares of the Corporation.

"**Sproule**" means Sproule Associates Limited.

"**Subscription Receipts**" means subscription receipts of Chronos.

"**Subscription Receipt Private Placement**" means the non-brokered private placement of Subscription Receipts of Chronos for aggregate gross proceeds of $53.0 million, as further described under "*General Development of the Business – Three-Year History – Financial Year Ended December 31, 2022*".

"**TSX-V**" means the TSX Venture Exchange.

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

"**Units**" means units of Chronos, each Unit being comprised of one Chronos Share and one Chronos Warrant, as further described under "*General Development of the Business – Three-Year History – Financial Year Ended December 31, 2022*".

"**Unit Private Placement**" means the non-brokered private placement of Units of Chronos for aggregate gross proceeds of $12.0 million, as further described under "*General Development of the Business – Three-Year History – Financial Year Ended December 31, 2022*".

"**Warrant**" means the Common Share purchase warrants of the Corporation, as further described under "*General Development of the Business – Three-Year History – Financial Year Ended December 31, 2022*".

ABBREVIATIONS

In this AIF, the abbreviations set forth below have the following meanings:

bbl	Barrel	mcf	thousand cubic feet
mbbl	thousand barrels	mcf/d	thousand cubic feet per day
bbl/d	barrels per day	mmcf	million cubic feet
NGLs	natural gas liquids	mmcf/d	million cubic feet per day
Boe/d	barrels of oil equivalent per day	MMBTU	million British Thermal Units
		Tcf	Trillion cubic feet

API	American Petroleum Institute.
°API	An indication of the specific gravity of Crude Oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light Crude Oil.
boe	Barrel of oil equivalent.
Mcfe	means 1,000 cubic feet equivalent on the basis of one Bbl of crude oil for six Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices).
CO_2	Carbon dioxide.
GHG	Greenhouse gas emissions.
Mboe	1,000 barrels of oil equivalent.
M$	Thousands of dollars.
WTI	West Texas Intermediate

CURRENCY

All currency amounts ($) expressed herein, unless otherwise indicated, are expressed in Canadian dollars.

CONVERSIONS

The following table sets forth certain standard conversions from Standard Imperial Units to the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
bbls	Cubic metres	0.159
Cubic metres	bbls	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471
Gigajoules	Mmbtu	0.949
Mmbtu	Gigajoules	1.055

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements contained in this AIF constitute forward-looking statements. The use of any of the words "anticipate", "intend", "continue", "estimate", "expect", "may", "will", "plan", "project", "should", "believe" and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Lycos believes the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forwarding-looking statements speak only as of the date of this AIF.

In particular, this AIF may contain forward-looking statements pertaining to the following:

- the business strategy, objectives, strengths, weaknesses and focus of the Corporation;
- the performance characteristics of the Corporation's oil and natural gas properties;

- oil and natural gas production levels;
- capital expenditure programs and estimates;
- the quantity of oil and natural gas proved and probable reserves;
- future commodity prices;
- the quantity and quality of the Corporation's inventory of drilling locations and the Corporation's plans with respect to development and operation of its properties, including estimates of drilling and completion costs and efficiency improvements;
- the estimated quantity and value of the Corporation's reserves;
- expectations with respect to the Corporation's financial position and future funds from operations, cash flows, net earnings and other financial results;
- the Corporation's current capital budget, capital investment programs and future capital requirements, including its ability to raise capital;
- expectations regarding contractual obligations and commitments, benefits therefrom and their expected timing of funding;
- future costs, including Abandonment and reclamation cost expectations;
- access to third-party infrastructure and the expected limitations, costs and benefits thereof;
- the use of risk-management techniques, including hedging;
- expectations that the Corporation's competitive advantages will yield successful execution of its business strategy and the degree of any such success achieved;
- the Corporation's treatment under governmental regulatory regimes and tax laws, including estimated tax pools and the Corporation's tax horizon;
- the Corporation's management team as it evolves, including the continuity of employment of any person;
- the compensation arrangements and economic interest of the Corporation's management team in the Corporation's equity and the benefits thereof;
- supply and demand for oil and natural gas;
- the ability of the Corporation to achieve drilling success consistent with management's expectations;
- the Corporation's ability to attract and retain qualified personnel;
- expected levels of royalty rates, operating costs, general and administrative costs, costs of services and other costs and expenses; and
- treatment under governmental, regulatory and royalty regimes and tax laws.

Although management of Lycos believes that the expectations reflected in the forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this AIF:

- adverse effects on general economic conditions in Canada, the United States and globally;
- the ability of management to execute its business plan;
- volatility in market prices for oil and natural gas, including due to the current conflict in Ukraine;
- risks and liabilities inherent in oil and natural gas industry, including environmental regulation;

- uncertainties associated with estimating oil and natural gas reserves, production, costs and expenses;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- actions taken by governmental authorities, including increases in taxes and changes in government regulations and incentive programs;
- risks inherent in marketing operations, including credit risk;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems;
- fluctuations in foreign exchange or interest rates and stock market volatility;
- changes in income tax laws and incentive programs relating to the oil and natural gas industry;
- unanticipated operating events which could reduce production or cause production to be shut- in or delayed;
- hazards such as fire, explosion, blowouts, cratering and spills, each of which could result in substantial damage to wells, production facilities, other property and the environment or in personal injury;
- insufficient storage or transportation capacity;
- risks relating to the condition of the Corporation's assets, and costs relating to maintenance of same;
- the ability to add production and reserves through development and exploration activities;
- the possibility that government policies or laws, including laws and regulations related to the environment, may change or governmental approvals may be delayed or withheld;
- the potential termination or expiration of the licenses, leases and working interest in licenses and leases required by the Corporation, and the risk that the Corporation may not be able to obtain all necessary licenses and permits required for its business;
- failure to obtain industry partner and other third party consents and approvals, as and when required;
- inflation, stock market volatility and market valuations;
- competition for, among other things, capital, acquisition of reserves, undeveloped land and skilled personnel;
- inability to identify and complete potential acquisitions and/or failure to achieve anticipated benefits from such acquisitions;
- inability to add production and reserves through development and exploration activities;
- termination of or failure to extend existing licenses by regulatory or governmental authorities;
- the availability of capital on acceptable terms or at all;
- failure to realize anticipated benefits of acquisitions;
- a resurgence in cases of COVID-19 or other virus strains, and the extent to which such infections impact Lycos, and its results of operations and financial condition; and
- the other factors discussed under "*Risk Factors*".

Statements relating to "reserves" and "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described can be profitably produced in the future.

With respect to forward-looking statements contained in this AIF, Lycos has made assumptions regarding, among other things:

- the legislative and regulatory environments of the jurisdictions where the Corporation carries on business or has operations;
- commodity prices and royalty regimes;
- the impact of increasing competition;
- availability of skilled labour;
- timing and amount of capital expenditures;
- the impact of inflation on operating and labour costs;
- the price of oil and natural gas;
- conditions in general economic and financial markets;
- royalty rates and future operating costs; and
- the Corporation's ability to obtain additional financing to finance its exploration, development and operations, and its ability to secure such financing on satisfactory terms.

Lycos has included the above summary of assumptions and risks related to forward-looking information provided in this AIF in order to provide investors with a more complete perspective on Lycos's current and future operations and such information may not be appropriate for other purposes.

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this AIF are expressly qualified by this cautionary statement. Except as required by applicable securities laws, Lycos does not undertake any obligation or is not under any duty to publicly update or revise any forward-looking statements. Readers should also carefully consider the matters discussed under the heading "*Risk Factors*" in this AIF.

NON-IFRS MEASURES, NON-IFRS FINANCIAL RATIOS AND CAPITAL MANAGEMENT MEASURES

This AIF contains certain financial measures and ratios, as described below, which do not have standardized meanings prescribed by IFRS. As these non-IFRS financial measures and ratios are commonly used in the oil and gas industry, Lycos believes that their inclusion is useful to investors. The reader is cautioned that these amounts may not be directly comparable to measures for other companies where similar terminology is used. The non-IFRS financial measures and ratios used in this AIF, represented by the capitalized and defined terms outlined below, are used by the Corporation as key measures of financial performance. For further information, readers should refer to the section entitled "Non-IFRS Measures, Non-IFRS Financial Ratios and Capital Measures" located in the management's discussion and analysis of the Corporation for the year ended December 31, 2022, available on the Corporation's SEDAR profile at www.sedar.com.

> "**Operating netback**" is calculated by deducting royalties, net operating expenses, and transportation expenses, from petroleum and natural gas revenues, excluding the effects of financial derivatives. Management believes that in addition to net income, operating netbacks are a useful supplemental measure as it assists in the determination of the Corporation's operating performance as it demonstrates field level profitability relative to current commodity prices. Readers should be cautioned, however, that this measure should not be construed as an alternative to both net income and net cash from (used in) operating activities, which are determined in accordance with IFRS, as indicators of the Corporation's performance.

($000s)	2022	2021	2022 ($/boe)	2021 ($/boe)
Petroleum and natural gas revenues	$31,270	$13,934	$85.32	$59.86
Royalties	(5,076)	(2,656)	(13.85)	(11.41)
Net operating expenses	(17,474)	(6,428)	(47.68)	(27.62)
Transportation expenses	(269)	(258)	(0.73)	(1.11)
Operating netback	**$8,451**	**$4,592**	**$23.06**	**$19.73**

"**Net operating expenses**" Management uses net operating expenses to analyze operating performance. Net operating expenses are determined by deducting processing income primarily generated by third party volumes at processing facilities where the Corporation has an ownership interest. However, the Corporation's principal business is not that of a midstream entity whose activities are dedicated to earning processing and other infrastructure payments. Where the Corporation has excess capacity at its facilities, it will look to process third party volumes as a means to reduce the cost of operating/owning the facility.

"**Capital expenditures**" Management uses the term "capital expenditures" as a measure of capital investment in exploration and production activity, as well as property acquisitions and dispositions, as such spending is compared to the Corporation's annual budgeted capital expenditures. The most directly comparable IFRS measure for capital expenditures is cash flow used in investing activities. A summary of the reconciliation of cash flow used in investing activities to capital expenditures is set forth below:

	Year ended December 31,	
	2022	2021
Net cash used in investing activities	8,280	1,719
Change in non-cash working capital	1,495	(32)
Capital Expenditures	**9,775**	**1,687**

NOTE ON COMMON SHARE CONSOLIDATION

On December 12, 2022, the Corporation consolidated (the "**Consolidation**") its Common Shares on the basis of one (1) post-Consolidation Common Share for every eight (8) pre-Consolidation Common Shares. Unless otherwise indicated, all references to the number of Common Shares and other securities of the Corporation and the prices thereto prior to the Consolidation date have been restated to reflect the Consolidation. As a result, restated figures may be slightly greater than or less than their pre-consolidated equivalent due to rounding.

NOTES ON RESERVES DATA AND OTHER OIL AND NATURAL GAS INFORMATION

Advisory Regarding Oil and Gas Information

The reserves information contained in this AIF has been prepared in accordance with NI 51-101 and COGE Handbook. Listed below are cautionary statement(s) that are specifically required by NI 51-101 that qualify the oil and gas disclosure contained in this AIF (including the Appendices hereto).

The terms "boe" and "mcfe" may be misleading, particularly if used in isolation. A boe conversion rate of six thousand cubic feet of natural gas per barrel of oil (6 mcf:1 bbl) and an mcfe conversion rate of one barrel of oil per six thousand cubic feet of natural gas (1 bbl:6 mcf) are each based on an energy equivalency conversion method primarily applicable at the burner tip and do not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of Crude Oil as compared to natural gas is significantly different from an energy equivalency of 6:1, utilizing a conversion ratio of 6:1 may be misleading as an indication of value.

Reserves

The discounted and undiscounted net present value of future net revenues attributable to the reserves of Lycos, do not represent the fair market value of such reserves. There is no assurance that the forecast prices and cost assumptions applied by the independent reserves evaluators in evaluating the reserves of Lycos will be attained and variances could be material. The estimates of heavy Crude Oil, NGL, and conventional natural gas reserves provided in this AIF are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual heavy Crude Oil, NGLs, and conventional natural gas reserves may be greater than or less than the estimates provided in this AIF and the difference may be material.

The determination of reserves involves the preparation of estimates that have an inherent degree of associated risk and uncertainty. The estimation and classification of reserves is a complex process involving the application of professional judgment combined with geological and engineering knowledge to assess whether specific classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions. In addition, rules set forth in the COGE Handbook and NI 51-101 override professional judgments as to volumes of recovery, well productivity and other factors.

The estimates of reserves and future net revenue for individual properties in this AIF may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

The information set forth in this AIF relating to the reserves of Lycos and related future net revenues constitutes forward-looking statements which are subject to certain risks and uncertainties. See "*Forward-Looking Statements*" and "*Risk Factors*" in this AIF.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions set forth below in "*Selected Oil and Gas Terms*" in this AIF are applicable to individual reserves entries (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90% probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
- at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves; and
- at least a 10% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

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

Drilling Locations

This AIF discloses drilling inventory in two categories: (a) proved reserve locations; and (b) probable reserve locations. Proved locations and probable locations are derived from Sproule's reserves evaluation effective December 31, 2022 and account for drilling locations that have associated proved and/or probable reserves, as applicable. Of the 45.89 net drilling locations identified herein, 26.89 are net proved locations, and 19.0 are net probable locations. The drilling locations on which the Corporation actually drills wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, commodity prices, costs, actual drilling results, additional reservoir information that is obtained and other factors.

Short Term Production

References in this AIF to short-term production rates are useful in confirming the presence of hydrocarbons, however such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long-term performance or of ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production of the Corporation.

Selected Oil and Gas Terms

In this AIF, unless otherwise indicated or the context otherwise requires, the following terms used in the preparation of the Reserves Report in accordance with NI 51-101 and this AIF have the meanings set forth below. These definitions are generally as set forth in the COGE Handbook and NI 51-101 and are reproduced below for the convenience of the reader.

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by The Society of Petroleum Evaluation Engineers (Calgary Chapter), as amended from time to time.

"**condensate**" means a mixture of hydrocarbons consisting primarily of pentanes and heavier liquids extracted from natural gas.

"**conventional natural gas**" means natural gas that has been generated elsewhere and has migrated as a result of hydrodynamic forces and is trapped in discrete accumulations by seals that may be formed by localized structural, depositional or erosional geological features.

"**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.

"**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 they shut in, they must have previously been on production, and on the date of resumption and production must be known with reasonable 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.

"**development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil, NGL and natural gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to: (a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building and relocating public roads, natural gas lines and power lines, to the extent necessary in developing the reserves; (b) drill and equipment development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly; (c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and (d) provide improved recovery systems.

"**development well**" means a well drilled inside the established limits of an oil or natural gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

"**exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and natural gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are: (a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies; (b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence and the maintenance of land and lease records; (c) dry hole contributions and bottom hole contributions; (d) costs of drilling and equipping exploratory wells; and (e) costs of drilling exploratory type stratigraphic test wells.

"**field**" means a defined geographical area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

"**forecast prices and costs**" means future prices and costs that are: (a) generally acceptable as being a reasonable outlook of the future; and (b) if and only to the extent that, there are fixed or presently determinable future prices or costs to which a company is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in the paragraph above.

"**gross**" means: (a) in relation to a company's interest in production or reserves, its "company gross reserves", which are the company's working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the company; (b) in relation to wells, the total number of wells in which a company has an interest; and (c) in relation to properties, the total area of properties in which a company has an interest.

"**heavy Crude Oil or heavy oil**" means Crude Oil with a relative density greater than 10 degrees API gravity and less than or equal to 22.3 degrees API gravity.

"**light Crude Oil or light oil**" means Crude Oil with a relative density greater than 31.1 degrees API gravity. Light and medium Crude Oil means light Crude Oil and medium Crude Oil combined.

"**medium Crude Oil**" or "**medium oil**" means Crude Oil with a relative density greater than 22.3 degrees API gravity and less than or equal to 31.1 degrees API gravity.

"**natural gas liquids**" or "**NGL**" means those hydrocarbon components that can be recovered from natural gas as a liquid including, but not limited to, ethane, propane, butanes, pentanes plus, and condensates.

"**net**" means: (a) in relation to a company's interest in production or reserves, the company's working interest (operating or nonoperating) share after deduction of royalty obligations, plus the company's royalty interest in production or reserves; (b) in relation to a company's interest in wells, the number of wells obtained by aggregating the company's working interest in each of its gross wells; and (c) in relation to a company's interest in a property, the total area in which the company has an interest multiplied by the working interest owned by the company.

"**net acres**" means the percentage of total acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.

"**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.

"**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.

"**reserves**" are 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: (i) analysis of drilling, geological, geophysical and engineering data; (ii) the use of established technology; and (iii) specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates.

"**reservoir**" means a porous and permeable underground rock formation containing a natural accumulation of petroleum that is confined by impermeable rock or water barriers, is separate from other reservoirs and is characterized by a single pressure system.

"**resources**" means petroleum quantities that originally existed on or within the earth's crust in naturally occurring accumulations, including discovered and undiscovered (recoverable and unrecoverable) plus quantities already produced.

"**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.

"**working interest**" means the right granted to the lessee of a property to explore for and to produce and own oil, natural gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

The information set forth in this AIF (inclusive of the Appendices hereto) relating to Lycos' reserves and future net revenues, respectively, constitutes forward-looking statements which are subject to certain risks and uncertainties. See "*Forward-Looking Statements*" and "*Risk Factors*" in this AIF.

CORPORATE STRUCTURE

Name, Address and Incorporation

The Corporation was incorporated under the ABCA on May 8, 2006 as "Samoth Oilfield Inc.". On December 12, 2022, the Corporation completed a business combination (the "**Business Combination**") involving Chronos and AcquisitionCo, a wholly owned subsidiary of the Corporation. The Business Combination was completed in accordance with the terms of a business combination agreement (the "**Business Combination Agreement**") dated November 7, 2022 among the Corporation, Chronos and AcquisitionCo. Pursuant to the Business Combination, the Corporation: (a) appointed a new management team; (b) appointed a new board of directors; (c) acquired all of the issued and outstanding Chronos Shares in exchange for 20 pre-Consolidation Common Shares; (d) underwent a name change from "Samoth Oilfield

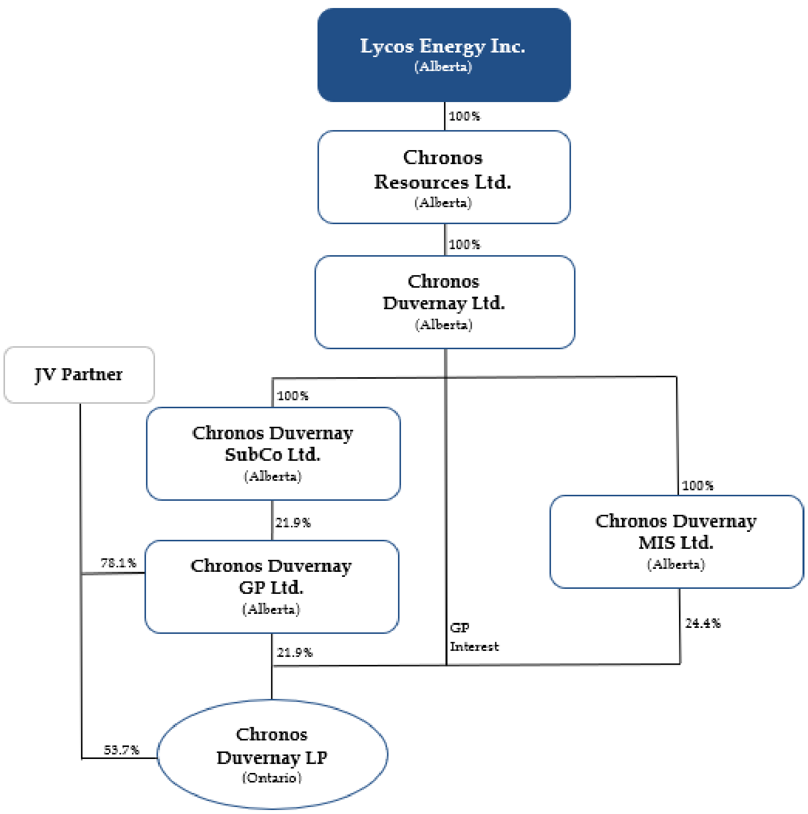
Inc." to "Lycos Energy Inc."; and (e) effected the Consolidation on the basis of one (1) post-Consolidation Common Share for every eight (8) pre-Consolidation Common Shares, representing an exchange ratio on a post-Consolidation basis of two and a half (2.5) Common Shares. Following the Business Combination, Chronos and AcquisitionCo amalgamated leaving the Corporation with a wholly-owned subsidiary named "Chronos Resources Ltd." On January 1, 2023, this subsidiary was vertically amalgamated with the Lycos.

The Corporation is governed by the ABCA. The head office of the Corporation is located at 215 – 2nd Street SW, Suite 1900, Calgary, Alberta, T2P 1M4 and the registered office of the Corporation is located at 4300 Bankers Hall West, 888 – 3rd Street S.W., Calgary, Alberta, T2P 5C5.

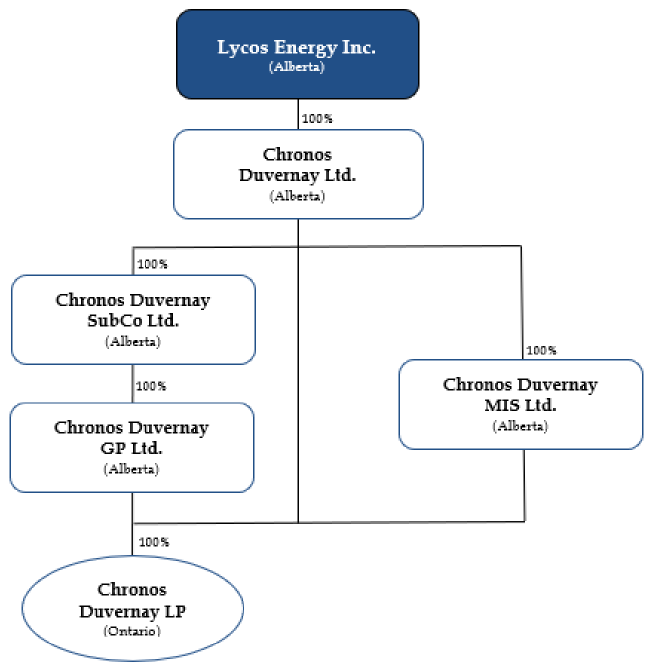
Intercorporate Relationships

The below organizational charts set out the Corporation's organizational structure and its material subsidiaries as at December 31, 2022 and as at April 27, 2023 (accounting for (i) the January 1, 2023 amalgamation of the Corporation and Chronos Resources Ltd. and (ii) the February 28, 2023 JV Acquisition):

December 31, 2022



April 27, 2023



GENERAL DEVELOPMENT OF THE BUSINESS

Recent Developments

- On April 3, 2023, Lycos announced a Board approved initial 2023 capital budget of $87 million ($50 million acquisition capital and $37 million exploration, development and other capital) and the promotions of Kyle Boon to the role of Chief Operating Officer and Barret Henschel to the role of Vice President, Production.

- On February 28, 2023, the Corporation completed the acquisition (the "**JV Acquisition**") of its joint venture partner's equity interest in the Partnership for a purchase price consisting of $50.0 million in cash and the grant of a 3% gross overriding royalty (the "**GORR**") to the former ownership group on any newly drilled wells on the acquired lands. The JV Acquisition added 56.2 net sections of land (45.8 undeveloped) and 1,500 boe/d to the Corporation's production, with an increase of more than 40 multi-lateral drills to current inventory.

- On February 25, 2023, the Corporation appointed KPMG as its new auditor. Prior to this appointment, Crowe Mackay LLP was auditor to the Corporation.

- On January 25th, 2023, Lycos issued the grant of 15,935,000 stock options to certain employees, directors and officers. The stock options expire five years from the date of grant and are exercisable at a price of $0.55 per common share. The options vest as to one-third on each of the first, second and third anniversary of the grant date.

- On January 16, 2023, Lycos entered into a credit agreement in respect of a new revolving credit facility for up to $20.0 million, of which $10.0 million is immediately available for general corporate purposes and an additional $10.0 million is available at the discretion of the Lender. The credit facility is undrawn, uncommitted and payable on demand.

Three-Year History

Financial Year Ended December 31, 2022

- On December 15, 2022, the Common Shares commenced trading on the TSX-V under the name "Lycos Energy Inc." and under the ticker symbol "LCX".

- On November 7, 2022, the Corporation, AcquisitionCo and Chronos entered into the Business Combination Agreement providing for the Business Combination. Pursuant to the terms of the Business Combination Agreement, on December 12, 2022, the Corporation:

    - appointed a new management team led by Dave Burton as President and Chief Executive Officer, Lindsay Goos as Vice President, Finance and Chief Financial Officer, Kyle Boon as Vice President, Operations, Jamie Conboy as Vice President, Exploration and Jeff Rideout as Vice President, Land;

    - appointed a new board of directors, comprised of Dave Burton, Kevin Olson, Ian Atkinson, Ali Horvath, Bruce Beynon, Don Cowie and Kel Johnston, with Neil Roszell serving as a Special Advisor to the Board;

    - acquired all of the issued and outstanding Chronos Shares in exchange for twenty (20) pre-Consolidation Common Shares at a deemed price of $0.035 per pre-Consolidation Common Share; and

    - effected the Name Change and Consolidation.

- In conjunction with the Business Combination, Chronos completed: (a) a non-brokered private placement (the "**Subscription Receipt Private Placement**") of subscription receipts ("**Subscription Receipts**") of Chronos for aggregate gross proceeds of $53.0 million; and (b) a non-brokered private placement (the "**Unit Private Placement**", and together with the Subscription Receipt Private Placement, the "**Chronos Financings**") of units ("**Units**") of Chronos for additional aggregate gross proceeds of $12.0 million. The net proceeds from the Chronos Financings were used to fund the February 28, 2023 JV Acquisition and in combination with working capital and general corporate purposes.

  - The 75,714,285 Subscription Receipts issued under the Subscription Receipt Private Placement at an offering price of $0.70 per Subscription Receipt were automatically exchanged for Chronos Shares on a one-to-one basis immediately prior to the closing of the Business Combination, following which each Chronos Share was acquired by the Corporation in exchange (the "**Exchange Ratio**") for twenty (20) pre-Consolidation Common Shares, and subject to the Consolidation, resulting in each holder of Subscription Receipts receiving two and a half (2.5) post-Consolidation Common Shares for each Subscription Receipt held.

  - Contemporaneous with the closing of the Business Combination, 17,142,858 Units were issued under the Unit Private Placement at an offering price of $0.70 per Unit. Each Unit was comprised of one Chronos Share and one Chronos Share purchase warrant (each, a "**Chronos Warrant**"). Each Chronos Share was subject to the Exchange Ratio following the closing of the Business Combination. Chronos Warrants were also subject to the Exchange Ratio resulting in holders of Units receiving two and a half (2.5) post-Consolidation Common Share purchase warrants (each, a "**Warrant**") for each Unit held. Each whole Warrant entitles the holder thereof to purchase one (1) post-Consolidation Common Share at an exercise price of $0.28 at any time prior to December 12, 2027. The Warrants shall vest and become exercisable as to one-third upon the 10-day weighted average trading price of the Common Share (the "**Market Price**") equaling or exceeding $0.42, an additional one-third upon the Market Price equaling or exceeding $0.49, and a final one-third upon the Market Price equaling or exceeding $0.56. As of the date hereof, all Warrants issued pursuant to the Unit Private Placement have vested.

- Lycos successfully drilled its first 100 percent, multi-leg "fishbone" well and a second 8 leg multi-lateral well from the same drilling pad location. Both wells were subsequently brought on production with an initial 30-day production rate (IP30) of approximately 150 boe/d and 97 boe/d.

Financial Year Ended December 31, 2021

- Pursuant to a purchase and sale agreement dated September 22, 2021 with Crew Energy Inc., an arm's length oil and gas producer, Chronos completed the acquisition of properties in the Lloydminster area of Saskatchewan on September 24, 2021, characterized by 400 bbl/d of heavy oil production for aggregate consideration of $1.1 million.

Financial Year Ended December 31, 2020

- The Corporation responded to the COVID-19 pandemic and dramatic commodity price decline by drastically reducing overall cost structure and sustaining its operations.

Significant Acquisitions

During the fiscal year ended December 31, 2022, the Corporation did not complete any significant acquisitions or significant dispositions or entered into any significant probable acquisitions, as defined in NI 51-102.

DESCRIPTION OF THE BUSINESS OF THE CORPORATION

Lycos is a crude oil and natural gas exploration, development and production company based in Calgary, Alberta, with operations in the Gull Lake area of southwest Saskatchewan and the Lloydminster region of Saskatchewan. As of December 31, 2022, Lycos' assets included proved plus probable reserves of 7,544 mboe and 42,304 net acres of undeveloped and developed lands.

On February 28, 2023, Lycos completed the JV Acquisition, adding assets in the Lloydminster region of Alberta to the Corporation's portfolio. As of the date hereof, current production of the Corporation is approximately 3,000 boe/d, comprised of 180 mcf/d of natural gas and 2,970 bbls/d of Crude Oil and NGLs, inclusive of the assets acquired through the JV Acquisition.

Description of Principal Properties

Lycos' principal oil and natural gas properties are focused in southwest Saskatchewan and Lloydminster Saskatchewan. The following is a description of Lycos' principal oil and natural gas properties as at December 31, 2022. Information in respect of current production is average production, net to Lycos' working interest, except where otherwise indicated. Estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Lloydminster Saskatchewan

The Lloydminster area includes Lycos operations at Baldwinton, Forest Bank, Golden Lake, Lashburn West and Neilburg, Tangleflags and Unwin-Epping and is situated in the Saskatchewan region near the city of Lloydminster, Saskatchewan. Lycos' production in the area is comprised of 12° to 14° API oil from several stacked Cretaceous aged reservoirs in the Mannville. Average production for the year ended December 31, 2022 was 572 bbl/d, 100% of which was from heavy oil. Development includes applying multi-lateral horizontal technology to redevelop lands and increase overall recovery. At December 31, 2022, Lycos owned 52 (47.6 net) producing oil wells, along with a 100% owned oil battery and numerous single and multi-well batteries located at individual well sites. The majority of Lycos' oil production from the Lloydminster area is processed at Lycos' 100% owned oil battery which is directly tied into the Manito Pipeline System. As at December 31, 2022, the Lycos Reserves Report attributed proved plus probable reserves of 3,389 mboe to this area, 3,389 mbbls of which was made up of heavy oil. As at December 31, 2022, the Corporation’s interests in the Lloydminster Saskatchewan area consisted of approximately 26,122 net acres.

In 2022, the Corporation drilled 2 gross (2.0 net) Baldwinton oil wells (one multi-lateral and one fishbone). Both wells were on production by year-end 2022.

Southwest Saskatchewan

The Saskatchewan property located in the Gull Lake area of southwest Saskatchewan consists of an average working interest of approximately 94% with average production for the year ended December 31, 2022 of 432 boe/d, 98% of which was from heavy oil and NGLs. As of December 31, 2022, Lycos owned 33 (30.9 net) producing oil wells. Lycos did not drill any wells during 2022, with the majority of activity focused on recompletion and production facilities related to reactivating existing wellbores. As at December 31, 2022, the Lycos Reserves Report attributed proved plus probable reserves of 4,155 mboe to this area, 4103 mbbls of which was made up of oil and NGLs. As at December 31, 2022, the Corporation’s interests in the Southwest Saskatchewan area consisted of approximately 13,569 net acres.

Partnership Properties

On June 14, 2018, the Corporation disposed of certain undeveloped properties held by Chronos into the Partnership, and entered into a partnership and financing agreement with a private equity firm for the development of its land base in the East Duvernay Shale basin in Alberta. As of December 31, 2022, the Corporation owned 21.85% and the private equity firm owned 78.15% of the equity interest in the Partnership. On February 28, 2023, the Corporation completed the JV Acquisition and, as at the date hereof, owns 100% of the Partnership and, as such, 100% of the assets (the "**Partnership Assets**") held by the Partnership. An overview of the Partnership Assets is provided below.

Lloydminster Alberta

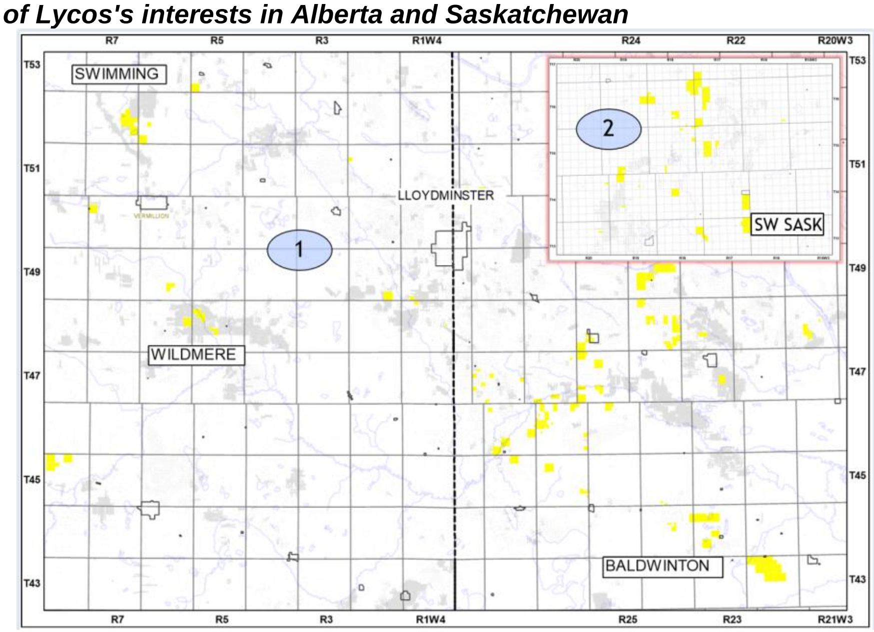
The Lloydminster area includes Chronos' operations at Wildmere, Swimming, Lloydminster and Wainwright. Chronos' production in the area is comprised of 12° to 14° API oil from several stacked Cretaceous aged reservoirs in the Manville. Development includes applying multileg horizontal technology to redevelop lands and increase overall recovery. The majority of the Partnership's oil production from the Lloydminster area is processed at Chronos' 100% owned oil battery which is directly tied into the Manito Pipeline System. As at December 31, 2022, the lands held in the Lloydminster Alberta area consisted of approximately 9,320 net acres.

In 2022, the Corporation drilled 6 gross (6.0 net) Swimming oil wells (five multi-laterals and one ½ fishbone). Four of these wells were on production by year-end 2022 and the remaining two came on production in Q1 2023.

Duvernay Alberta

The Alberta Duvernay property is in the Ghost Pine embayment of the East Duvernay Shale Basin, located in the Elnora and Mikwan area of west central Alberta. As at December 31, 2022, the lands held consisted of a 100% working interest in approximately 26,990 net acres. The Duvernay assets are an exploration play.

Figure 1: Map of Lycos's interests in Alberta and Saskatchewan



Specialized Skill and Knowledge

Lycos relies on specialized skills and knowledge to gather, interpret and process geological and geophysical data; drill and complete wells; design and operate production facilities; and numerous additional activities required to explore for, acquire and produce oil and natural gas. Lycos' permanent staff have training and experience in the disciplines of engineering, finance, geology and land.

It is the belief of management that the Corporation's officers and employees, who have significant technical and operational oil and gas experience, hold the necessary skill sets to successfully execute Lycos' business strategy in order to achieve its corporate objectives.

Competitive Conditions

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

Cyclical and Seasonal Nature of Industry

The Corporation's financial performance and financial condition will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect on Lycos's financial condition. For more information, see "*Industry Conditions – Recent Developments*".

Economic Dependence

The Corporation has ensured economic diversity by not being substantially dependent on any single contract or license, such as a contract to sell the major part of its products or services or to purchase the majority of its goods, services or raw materials, or any franchise, licence or other agreement to use a patent, formula, trade secret, process or trade name upon which Lycos' business depends**.**

Changes to Contracts

The Corporation does not reasonably anticipate being materially affected by renegotiation or termination of contracts or sub-contracts.

Environmental Policies and Responsibility

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislations. Compliance with such legislation can require significant expenditures or result in operational restrictions. Breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties, all of which might have a significant negative impact on earnings and overall competitiveness.

The operations of the Corporation are, and will continue to be, affected in varying degrees by laws and regulations regarding environmental protection. Lycos is committed to meeting its responsibilities to protect the environment and will be taking such steps as required to ensure compliance with environmental legislation in all jurisdictions in which it operates. For a further discussion of the environmental regulations affecting the oil and gas industry, see "*Industry Conditions*" and "*Risk Factors*".

Employees

As of December 31, 2022, Lycos employed 15 individuals at its head office in Calgary, Alberta and 7 individual(s) in the field.

Reorganizations

No material reorganizations have been either completed or proposed during the current financial year other than the Business Combination.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Reserves Data (Forecast Prices and Costs)

The reserves data set forth below (the "**Reserves Data**") is based upon the evaluation by Sproule with an effective date of December 31, 2022, contained in the Reserves Report with a preparation date of March 14, 2023, and for greater certainty, excludes reserves information in respect of the Partnership Assets which Lycos acquired 100% interest over through the JV Acquisition. The Reserves Data summarizes the Crude Oil, NGL and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using forecast prices and costs. The Reserves Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and the COGE Handbook. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which Lycos believes is important to the readers of this information. The Corporation engaged Sproule to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

The net present value of future net revenue attributable to the Corporation's reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and Well abandonment costs for only those wells assigned reserves by Sproule. It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained, and variances could be material. The recovery and reserve estimates of the Corporation's Crude Oil, NGL and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual Crude Oil, natural gas and NGL reserves may be greater than or less than the estimates provided herein.

The properties evaluated are located in the Province of Saskatchewan, Canada. **Numbers may not add due to rounding.**

SUMMARY OF OIL AND GAS RESERVES
(Forecast Costs and Prices)

Company Reserves								
Total Company	Heavy Oil (Mbbl)		NGL (Mbbl)		Conventional Natural Gas (MMcf)		Total Oil Equivalent (Mboe)	
Reserves Category	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved Developed Producing	1,492	1,291	0.3	0.3	111	102	1,510	1,308
Proved Developed Non-Producing	155	136	-	-	3	2	155	137
Proved Undeveloped	2,235	2,097	0.2	0.2	66	62	2,246	2,107
Total Proved	3,881	3,524	0.5	0.5	180	166	3,912	3,552
Probable	3,610	3,215	0.4	0.4	131	121	3,633	3,236
Total Proved Plus Probable	7,491	6,739	0.9	0.9	311	287	7,544	6,788

Notes:
(1) Due to rounding, certain totals may not add.

NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/YEAR)

(Forecast Costs and Prices)

Net Present Value of Future Net Revenue							
Total Company	Before Income Taxes, Discounted at (% / year)					Unit Value Before Income Tax, Discounted at 10% / year	
Reserves Category	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)	$/boe	$/MCfe
Proved Developed Producing	14,852	18,145	18,895	18,745	18,253	14.44	2.41
Proved Developed Non-Producing	2,917	2,679	2,473	2,293	2,136	18.12	3.02
Proved Undeveloped	65,114	45,769	33,463	25,231	19,461	15.88	2.65
Total Proved	82,883	66,593	54,831	46,269	39,850	15.44	2.57
Probable	127,022	87,017	64,161	49,799	40,085	19.83	3.31
Total Proved Plus Probable	209,905	153,610	118,992	96,068	79,935	17.53	2.92

Notes:

(1) Due to rounding, certain totals may not add.
(2) Barrel of Oil Equivalent (BOE): 6 Mcf = 1 BOE.
(3) Unit values are based on net reserve volumes.

NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAXES DISCOUNTED AT (%/YEAR)

(Forecast Costs and Prices)

Net Present Value of Future Net Revenue							
Total Company	After Income Taxes, Discounted at (% / year)					Unit Value After Income Tax, Discounted at 10% / year	
Reserves Category	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)	$/boe	$/MCfe
Proved Developed Producing	14,852	18,145	18,895	18,745	18,253	14.44	2.41
Proved Developed Non-Producing	2,917	2,679	2,473	2,293	2,136	18.11	3.02
Proved Undeveloped	65,114	45,769	33,463	25,231	19,461	15.88	2.65
Total Proved	82,883	66,593	54,831	46,269	39,850	15.44	2.57
Probable	95,020	66,175	49,631	39,163	32,012	15.34	2.56
Total Proved Plus Probable	177,903	132,768	104,462	85,432	71,862	15.39	2.57

Notes:

(1) Due to rounding, certain totals may not add.
(2) Barrel of Oil Equivalent (BOE): 6 Mcf = 1 BOE.
(3) Unit values are based on net reserve volumes.

FUTURE NET REVENUE (UNDISCOUNTED)

Reserves Category	Company Revenue (M$)	Burden and NPI (M$)	Development Costs (M$)	Abandonment Costs (M$)	Operating Expense (M$)	Future Net Revenue (M$)	Income Tax (M$)	Future Net Revenue After Income Tax (M$)
Proved Developed Producing	129,238	19,825	125	26,483	67,953	14,852	-	14,852
Total Proved	333,915	36,042	28,680	28,458	157,852	82,883	-	82,883
Total Proved Plus Probable	659,678	75,097	50,328	30,199	294,149	209,905	32,002	177,903

Notes:

(1) Due to rounding, certain totals may not add.

FUTURE NET REVENUE BY PRODUCT TYPE

Reserves Category	Production Group	Future Net Revenue Before Income Tax, Discounted at 10%/Year (M$)	Unit Value Before Income Tax, Discounted at 10%/Year ($/boe)	Unit Value Before Income Tax, Discounted at 10%/Year ($/Mcfe)
Proved Developed Producing				
	Heavy Oil	18,895	14.44	2.41
	NGL	-	-	-
	Conventional Natural Gas	-	-	-
Total: Proved Developed Producing		18,895	14.44	2.41

Reserves Category	Production Group	Future Net Revenue Before Income Tax, Discounted at 10%/Year (M$)	Unit Value Before Income Tax, Discounted at 10%/Year ($/boe)	Unit Value Before Income Tax, Discounted at 10%/Year ($/Mcfe)
Total Proved				
	Heavy Oil	54,831	15.44	2.57
	NGL	-	-	-
	Conventional Natural Gas	-	-	-
Total: Total Proved		54,831	15.44	2.57
Total Proved Plus Probable				
	Heavy Oil	118,992	17.53	2.92
	NGL	-	-	-
	Conventional Natural Gas	-	-	-
Total: Total Proved Developed Producing		118,992	17.53	2.92

Notes:

(1) Unit values are based on net reserve volumes.
(2) Barrel of Oil Equivalent (BOE): 6 Mcf = 1 BOE.
(3) Heavy oil values include solution gas and associated by-products.

PRICING ASSUMPTIONS

Sproule employed the following pricing and inflation rate assumptions as of December 31, 2022 in its evaluation in estimating reserves data using forecast prices and costs.

Year	WTI Cushing Oklahoma ($US/bbl)	Canadian Western Select 20.5 API ($Cdn/bbl)	Alberta AECO – C Spot ($Cdn/M mbtu)	Edmonton Pentanes Plus ($Cdn/bbl)	Edmonton Butane ($Cdn/bbl)	Edmonton Propane ($Cdn/bbl)	Operating Cost Inflation Rate (%Yr)	Capital Cost Inflation Rate (%Yr)	Exchange Rate ($US/$Cdn)
Forecast									
2023	86.00	88.00	4.33	114.87	54.47	38.13	0.0%	0.0%	0.75
2024	84.00	89.83	4.34	105.00	52.50	37.28	3.0%	3.0%	0.80
2025	80.00	84.06	4.00	100.00	50.00	37.88	2.0%	2.0%	0.80
2026	81.60	85.74	4.08	102.00	51.00	38.44	2.0%	2.0%	0.80
2027	83.23	87.46	4.16	104.04	52.02	39.21	2.0%	2.0%	0.80
2028	84.90	89.21	4.24	106.12	53.06	39.99	2.0%	2.0%	0.80
2029	86.59	90.99	4.33	108.24	54.12	40.79	2.0%	2.0%	0.80
2030	88.33	92.81	4.42	110.41	55.20	41.61	2.0%	2.0%	0.80
2031	90.09	94.67	4.50	112.62	56.31	42.44	2.0%	2.0%	0.80
2032	91.89	96.56	4.59	114.87	57.43	43.29	2.0%	2.0%	0.80
Escalation Rate of 2.0% thereafter									

RECONCILIATION OF CHANGES IN RESERVES

Reserves Reconciliation

The following table sets forth a reconciliation of the changes in the Corporation's gross reserves as at December 31, 2022, against the Corporation's reserves as at October 31, 2022 (prior to the Business Combination with Chronos), the most recently completed financial year end (summarized in the tables above) based on the forecast price and cost assumptions evaluated in accordance with NI 51-101 definitions:

Total Company	**Heavy Oil**			**Light / Medium Oil**			**Condensate**		
Factors	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)
October 31, 2022									
Discoveries	-	-	-	-	-	-	-	-	-
Extensions	-	-	-	-	-	-	-	-	-
Infill Drilling	-	-	-	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-	-	-	-
Technical Revisions	-	-	-	-	-	-	-	-	-
Acquisitions	3,881	3,610	7,491	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-

Total Company	Heavy Oil			Light / Medium Oil			Condensate		
Factors	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)
Economic Factors	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	-	-	-	-
December 31, 2022	3,881	3,610	7,491	-	-	-	-	-	-

Total Company	NGL			Conventional Natural Gas			Total BOE		
Factors	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (Mboe)	Gross Probable (Mboe)	Gross Proved Plus Probable (Mboe)
October 31, 2022									
Discoveries	-	-	-	-	-	-	-	-	-
Extensions	-	-	-	-	-	-	-	-	-
Infill Drilling	-	-	-	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-	-	-	-
Technical Revisions	-	-	-	-	-	-	-	-	-
Acquisitions	0.5	0.4	0.9	180	131	311	3,912	3,633	7,544
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	-	-	-	-
December 31, 2022	0.5	0.4	0.9	180	131	311	3,912	3,633	7,544

Reserve Change Category Descriptions:

Discoveries:	Additions in fields/reservoirs where no reserves were previously booked.
Extensions:	Additions for step-out drilling in previously discovered/booked reservoirs.
Infill Drilling:	Additions for infill drilling in previously discovered/booked reservoirs. Not related to enhanced recovery schemes.
Improved Recovery:	Additions resulting from the initiation of improved recovery schemes.
Technical Revisions:	Positive or negative changes resulting from new technical data or revised interpretations of previously assigned reserves.
Acquisitions:	Additions related to purchasing oil and gas assets.
Dispositions:	Reductions related to selling oil and gas assets.
Economic Factors:	Changes due to different price forecasts, inflation rates, and regulatory changes.
Production:	Reductions due to production during the time period being reconciled.

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

The following discussion generally describes the basis on which Lycos attributes proved and probable undeveloped reserves and its plans for developing those undeveloped reserves.

The Corporation currently plans to pursue the development of its proved and probable undeveloped reserves within the next two years through ordinary course capital expenditures. However, the Corporation may choose to delay development depending on a number of circumstances, including the existence of higher priority expenditures and prevailing commodity prices and cash flow.

The following tables set forth the proved undeveloped reserves and the probable undeveloped reserves, each by product type, attributed to the Corporation's assets for the years ended December 31, 2022, 2021 and 2020.

Proved Undeveloped Reserves

Proved undeveloped reserves are generally those reserves related to wells that have been tested and not yet tied-in, wells drilled near the end of the fiscal year or wells further away from gathering systems. In addition, such reserves may relate to planned infill-drilling locations.

SUMMARY OF PROVED UNDEVELOPED RESERVES
(Forecast Prices & Costs)

Company Gross Reserves												
	Heavy Oil (Mbbl)		Light and Medium Oil (Mbbl)		Condensate (Mbbl)		NGL (Mbbl)		Conventional Natural Gas (MMcf)		Total Oil Equivalent (Mboe)	
Year	Attributed	Current Total	Attributed	Current Total	Attributed	Current Total	Attributed	Current Total	Attributed	Current Total	Attributed	Current Total
December 31, 2020	-	-	-	-	-	-	-	-	-	-	-	-
December 31, 2021	-	-	-	-	-	-	-	-	-	-	-	-
December 31, 2022	2,235	2,235	-	-	-	-	0.2	0.2	66	66	2,246	2,246

Probable Undeveloped Reserves

Probable reserves are generally reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production.

SUMMARY OF PROBABLE UNDEVELOPED RESERVES
(Forecast Prices & Costs)

Company Gross Reserves												
	Heavy Oil (Mbbl)		Light and Medium Oil (Mbbl)		Condensate (Mbbl)		NGL (Mbbl)		Conventional Natural Gas (MMcf)		Total Oil Equivalent (Mboe)	
Year	Attributed	Current Total	Attributed	Current Total	Attributed	Current Total	Attributed	Current Total	Attributed	Current Total	Attributed	Current Total
December 31, 2020	-	-	-	-	-	-	-	-	-	-	-	-
December 31, 2021	-	-	-	-	-	-	-	-	-	-	-	-
December 31, 2022	3,069	3,069	-	-	-	-	0.3	0.3	106	106	3,086	3,086

Significant Factors or Uncertainties

The evaluated oil and gas properties of the Corporation have no material extraordinary risks or uncertainties beyond those which are inherent of an oil and gas producing company. Some of these risks are noted below.

The process of estimating reserves is complex. Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and natural gas prices and costs change. Estimates are reviewed and revised, either upward or downward, as warranted by newly acquired information.

The evaluation and drilling of hydrocarbon targets may be curtailed, delayed or cancelled by the unavailability or prevailing cost of drilling rigs or technical contractors, mechanical difficulties, adverse weather and ocean conditions, environmental issues, political or social unrest, technical hazards, such as unusual or unexpected formations or pressures or because of issues related to compliance with government regulations or requirements. Drilling may result in unprofitable efforts, not only with respect to dry wells, but also with respect to wells which, though yielding some hydrocarbons, are not sufficiently productive to economically justify commercial development. Furthermore, the successful completion of a well does not assure a profit on investment or the recovery of drilling, completion and operating costs.

Future Development Costs

The following table sets forth the development costs which have been deducted in the estimation of the Corporation's future net revenues of the reserves evaluated in the Reserves Report for the year ended December 31, 2022.

Future Development Costs
Estimated Using Forecast Prices and Costs (Undiscounted)

	Year				
Reserves Category	2023 (M$)	2024 (M$)	2025 (M$)	2026 (M$)	2027 (M$)
Proved Developed Producing	125	-	-	-	-
Proved Developed Non-Producing	820	-	-	-	-
Proved Undeveloped	5,544	10,435	10,926	831	-
Total Proved	6,489	10,435	10,926	831	-
Probable	4,854	10,605	5,358	831	-
Total Proved Plus Probable	11,342	21,040	16,284	1,661	-

The Corporation can fund its capital expenditure programs through internally generated cash flow from operations, debt financing when appropriate, new issues of Common Shares, if available on favourable terms, and funds raised from the sale of non-core assets, or a combination thereof. The Corporation expects to fund the above future development costs primarily through internally generated cash flow and debt and equity financings. There can be no guarantee that the Board of Directors will allocate funding to develop all of the reserves attributed in the Reserves Report. Failure to develop those reserves could have a negative impact on the Corporation's future cash flow.

Interest or other costs of external funding are not included in our reserves and future net revenue estimates and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. The Corporation does not anticipate that interest or other funding costs would make development of any its properties uneconomic.

OTHER OIL AND GAS INFORMATION

Oil and Gas Properties

The following table sets forth the number and status of wells as at December 31, 2022 in which Lycos has a working interest. All of the wells in which Lycos has an interest are located in the Provinces of Alberta and Saskatchewan.

Property Description	**Oil**		**Gas**	
	Gross	Net	Gross	Net
Producing	105	99.4	3	2.4
Non-Producing	358	330.0	14	11.6
Total	463	429.4	17	14.0

Notes:
1. "**Gross**" wells mean the number of wells in which Lycos has a working interest or a royalty interest that may be converted into a working interest.
2. "**Net**" wells mean the aggregate number of wells obtained by multiplying each gross well by Lycos percentage working interest therein.

For more information about the Corporation's oil and gas properties, please see "*Description of the Business of the Corporation*".

Properties With No Attributed Reserves

The following table sets out our developed and undeveloped land holdings as at December 31, 2022:

Province	Undeveloped Acres		Developed Acres		Total[(1)(2)]	
	Gross	Net	Gross	Net	Gross	Net
Alberta	633	633	2,218	1,981	2,850	2,613
Saskatchewan	22,314	21,857	20,228	17,834	42,543	39,691
Total	**22,947**	**22,490**	**22,446**	**19,815**	**45,393**	**42,304**

Notes:

1. Rights to explore, develop and exploit 400 gross (400 net) acres of our land holdings could expire by December 31, 2023 if not continued. We have no material work commitments on such properties and where we determine prudent to do so, we can extend expiring leases by either making the necessary applications to extend or performing the necessary work.
2. When determining gross and net acreage for two or more leases covering the same lands but different rights, the acreage is reported for each lease. Where there are multiple discontinuous rights in a single lease, the acreage is reported only once.

Forward Contracts

The Corporation is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments may be used by Lycos from time to time to reduce its exposure to fluctuations in commodity prices and foreign exchange rates. The Corporation is exposed to losses in the event of default by the counterparties to these derivative instruments. The Corporation manages this risk by contracting with large, well-capitalized counterparties.

Lycos may use certain financial instruments to hedge exposure to commodity price fluctuations on a portion of its future crude oil and natural gas production. For further information, see "*Risk Factors – Hedging*".

For details of the Corporation's forward contracts in place as at December 31, 2022, see the Corporation's audited annual financial statements for the year ended December 31, 2022, which have been filed on SEDAR and may be viewed under the Corporation's profile at www.sedar.com. See "Risk Factors Hedging".

Additional Information Concerning Abandonment and Reclamation Costs

The Corporation performs an annual review of its forecasted abandonment and site reclamation ("**Abandonment**") costs. These costs are based on information published by the AER with respect to AER Licensee Liability Management Program in Alberta (in respect of the Corporation's Alberta assets) and by the Saskatchewan Licensee Liability Rating Program (in respect of the Corporation's Saskatchewan assets). The Corporation's review is further augmented with adjustments on an individual well and facility basis. The review considers the following factors in assessing liability: well depth, nature of the production stream, the nature, location and condition of the surface lease, age of the well and/or facility, number of zones to be abandoned, and presence of salvageable equipment such as tanks, tubing, and rods. The Abandonment cost determined is net of salvage. The Abandonment costs estimated here include non-producing wellbores that have no attributed reserves.

Total Abandonment costs are included in the reserves data summarized as follows:

Year	Proved Developed Producing (M$)	Total Proved (M$)	Total Proved Plus Probable (M$)
2023	1,200	1,200	1,200
2024	1,236	1,236	1,236
2025	1,261	1,261	1,261
2026	1,286	1,286	1,286
2027	1,312	1,312	1,312
2028	1,338	1,338	1,338

Year	Proved Developed Producing (M$)	Total Proved (M$)	Total Proved Plus Probable (M$)
2029	915	915	915
2030	1,830	1,830	1,830
2031	2,510	2,510	2,510
2032	2,595	2,595	2,595
2033	1,807	1,807	1,807
2034	2,310	2,310	2,353
2035	835	835	835
2036	-	-	-
Subtotal	20,434	20,434	20,477
Remainder	6,048	8,024	9,722
Total	26,483	28,458	30,199

Additional information related to the Corporation's estimated share of future environmental and reclamation obligations for the working interest properties (including all abandonment and reclamation costs associated with all existing wells, facilities and infrastructure) can be found in Lycos' audited financial statements for the year ended December 31, 2022 and the accompanying management's discussion and analysis, which have been filed on SEDAR and may be viewed under the Corporation's profile at www.sedar.com.

Tax Horizon

Based on planned capital expenditures and the forecast commodity pricing employed in the Reserves Report, the Corporation estimates that it will not be required to pay current income taxes before 2024.

Costs Incurred

The following table summarizes the capital expenditures related to the Corporation's activities for the year ended December 31, 2022 related to exploration, development, and evaluation expenditures and property and equipment:

Year ended Dec. 31, 2022	**Property Acquisition Costs**		**Exploration Costs (M$)**	**Development Costs (M$)**
Country	Proved Properties (M$)	Unproved Properties (M$)		
Canada	-	-	-	10,091

The Corporation has no interests in or expenditures for non-conventional oil and gas properties.

Exploration and Development Activities

The following table sets forth the gross and net exploration and development wells drilled by the Corporation based on rig release date during the year ended December 31, 2022.

Activity	**Exploration Wells**		**Development Wells**	
	Gross	Net	Gross	Net
Oil Wells	-	-	2.0	2.0
Total Wells	-	-	2.0	2.0

Notes:
3. "**Gross Wells**" are the total number of wells in which the Corporation has an interest.
4. "**Net Wells**" are the number of wells obtained by aggregating the Corporation's working interest in each of its gross wells.

Planned Capital Expenditures

The Corporation has announced an initial capital expenditures budget of $87 million for 2023 comprised of $50 million of acquisition capital and $37 million of planned exploration, development and other capital.

Production Estimates

The following table discloses for each product type the total volume of production estimated by Sproule for 2023 in the estimates of future net revenue from the forecast case of proved plus probable reserves disclosed above under the heading "*Oil and Natural Gas Reserves and Net Present Value of Future Net Revenue*".

Company Gross (2023)								
Total Company	Heavy Oil (bbl/d)		NGL (bbl/d)		Conventional Natural Gas (Mmcf/d)		Total Oil Equivalent (boe/d)	
Reserves Category	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Total Proved								
SW Saskatchewan	425	363	0.10	0.10	0.05	0.05	433	371
Lloydminster SK	821	732	-	-	-	-	821	732
Total Proved	**1,245**	**1,095**	**0.10**	**0.10**	**0.05**	**0.05**	**1,254**	**1,103**
Total Proved Plus Probable								
SW Saskatchewan	462	396	0.10	0.10	0.05	0.05	470	404
Lloydminster SK	1,106	1,003	-	-	-	-	1,106	1,003
Total Proved Plus Probable	**1,568**	**1,399**	**0.10**	**0.10**	**0.05**	**0.05**	**1,577**	**1,408**

Notes:

1. Due to rounding, certain totals may not add.
2. Rate represent full year (365 day) average rates

Production History

The following tables set forth certain information in respect of production, product prices received, royalties, production costs and netbacks received by the Corporation for each quarter of its most recently completed financial year:

Total Company	Q1 2022	Q2 2022	Q3 2022	Q4 2022
Company Gross Production				
Heavy Oil (bbl/d)	895	892	1,075	1,109
Natural Gas (Mcf/d)	45	67	49	85
Boe/d	903	903	1,083	1,123
Average Prices				
Heavy Oil ($/bbl)	91.37	107.85	92.96	57.20
Natural Gas ($/bbl)	4.46	7.00	3.96	4.76
$/boe	90.83	107.03	92.43	56.84

Royalties

Total Company	Q1 2022	Q2 2022	Q3 2022	Q4 2022
Royalties (M$)	1,193	1,301	1,579	1,003
$/boe	14.68	15.82	15.84	9.70
Percent of Revenue (%)	16.2	14.8	17.1	17.1

Net Operating Expenses

Total Company	Q1 2022	Q2 2022	Q3 2022	Q4 2022
Net Operating Expense (M$)	3,342	4,641	5,341	4,150
$/boe	41.13	56.43	53.59	40.16

Transportation Expenses

Total Company	Q1 2022	Q2 2022	Q3 2022	Q4 2022
Transportation Expense (M$)	56	72	63	78
$/boe	0.69	0.88	0.63	0.75

Operating Netbacks

Total Company	Q1 2022	Q2 2022	Q3 2022	Q4 2022
Production (boe/d)	903	903	1,083	1,123
Revenue	90.83	107.03	92.43	56.84
Royalties	14.68	15.82	15.84	9.70
Net Operating Expense	41.13	56.43	53.59	40.16
Transportation Expense	0.69	0.88	0.63	0.75
Operating Netback	34.33	33.90	22.37	6.22

Production Volume by Field

The following table discloses for each important field and in total, the Corporation's production volume for the year ended December 31, 2022 for each product type:

Field	2022 Company Gross					
	Heavy Oil (bbl/d)	L/M Oil (bbl/d)	Condensate (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Total (boe/d)
Canada						
Lloydminster Saskatchewan	571	-	-	-	-	571
Southwest Saskatchewan	422	-	-	-	62	433
Total	993	-	-	-	62	1,004

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive regulation and control of operations (including with respect to land tenure, exploration, development, production, refining and upgrading, transportation and marketing) as a result of legislation enacted by various levels of government and with respect to the pricing and taxation of crude oil and natural gas through legislation enacted by, and agreements among, the federal and provincial governments of Canada, all of which should be carefully considered by investors in the Canadian petroleum and natural gas industry. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. While it is not expected that any of these controls or regulations will affect the operations of the Corporation in a manner materially different than they would affect other oil and gas corporations of similar size, investors should consider such legislation, regulations and agreements carefully. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and natural gas industry in Western Canada.

Pricing and Marketing in Canada

Crude Oil

In Canada, the producers of oil are entitled to negotiate sales contracts directly with oil purchasers, which means that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand, but regional market and transportation issues also influence prices. Specific prices that a producer receives will depend, in part, on oil quality, prices of competing fuels, distance to market, access to downstream transportation, value of refined products, length of contract term, weather conditions, the balance of supply and demand and other contractual terms.

In 2020, worldwide oversupply of crude oil, a lack of available storage capacity and decreased demand due to COVID-19 have had a continuing significant impact on the pricing of crude oil. In an effort to stabilize global oil markets, The Organization of Petroleum Exporting Companies ("**OPEC**") and a number of other oil producing countries announced an agreement to cut crude oil production by approximately 10 million bbl/d in April 2020, which was amended and adjusted throughout 2020 and early 2021. The oil markets began to rebalance in 2021 with oil prices reaching their highest levels in six years. The rebound continued into 2022 with a surge in oil prices in early 2022 primarily in response to the impact of the Russian invasion of Ukraine and the OPEC+ decision to adhere to previously agreed upon production cuts, together with the improvement of global economic conditions and outlook due to reduced and eased COVID-19 restrictions. However, prices began to drop in the latter half of 2022. Amid fear of a global recession, increasing interest rates and continuing COVID-19 restrictions in China, lower demand and continuing sanctions and price caps placed on Russian oil, oil prices began to drop in the summer of 2022, with Saudi Arabia capping production and the Group of Seven nations agreeing to put a price cap on Russian oil. At a meeting in early December 2022, OPEC+ decided to maintain its oil output targets following its decision in October 2022 to cut output by 2 million barrels per day. In December 2022, the ban placed on seaborne exports of Russian crude oil by the European Union came into effect, with the European Union also announcing price caps on Russian oil. The Group of Seven nations also announced a price cap of US$60 on Russian oil in December 2022. With a continuing shift to alternative energy sources, there has been a decline in oil demand growth, which is expected to continue into 2023. While the trajectory of oil prices continue to be subject to uncertainty and volatility, factors such as the conflict in Ukraine continue to be unpredictable and may have an ongoing impact on oil demand and prices. See "*Risk Factors – Impact of the COVID-19 Pandemic and Risks Related Thereto*" and "*Risk Factors – Commodity Prices, Markets and Marketing*".

Natural Gas Liquids

The pricing of condensates and other NGLs such as ethane, butane, propane and pentane plus sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. The profitability of NGLs extracted from natural gas is based on the products extracted being of greater economic value as separate commodities than as components of natural gas and therefore commanding higher prices. Such prices depend, in part, on the quality of the NGLs, price of competing chemical stock, distance to market, access to downstream transportation, length of contract term, supply/demand balance and other contractual terms.

Natural Gas

Negotiation between buyers and sellers determines the price of natural gas sold in intra-provincial, interprovincial and international trade. The price received by a natural gas producer depends, in part, on the price of competing natural gas supplies and other fuels, natural gas quality, distance to market, availability of transportation, length of contract term, weather conditions, supply/demand balance and other contractual terms of sale. Spot and future prices can also be influenced by supply and demand fundamentals on various trading platforms.

Exports from Canada

In the summer of 2019, the National Energy Board (the "**NEB**"*)* was replaced with the Canadian Energy Regulator (the "**CER**"). The CER's governing legislation is the *Canadian Energy Regulator Act* (the *CERA)* and the *Impact Assessment Act* (the "**IAA"**).The CER assumed the NEB's responsibilities broadly, including with respect to the export of crude oil, natural gas and NGL from Canada.

Exports of crude oil, NGLs and natural gas from Canada are subject to CERA and remain subject to the *National Energy Board Act Part VI (Oil and Gas) Regulation* (the "**Part VI Regulation**") until such time as the Part VI Regulation is replaced. The CERA and the Part VI Regulation authorize crude oil, NGLs and natural gas exports under: (i) short-term orders for up to one or two years depending on the substance, and up to 20 years for quantities of natural gas not exceeding 30,000 m^3 per day; or (ii) long-term export licences of up to 40 years for natural gas and up to 25 years for crude oil and other substances (e.g. NGLs). With respect to applications for long-term export licenses, following a review of such applications by the CER, which may involve a public hearing, the CER can approve an application if it is satisfied, among other considerations, that the proposed export volumes are not greater than Canada's reasonably foreseeable needs. In addition to CER approval, long-term export licences also currently require various other ministerial and federal Cabinet approvals.

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.

Transportation Constraints, Pipeline Capacity and Market Access

As discussed in more detail below, one major constraint to the export of crude oil, NGLs and natural gas is the deficit of transportation capacity to transport production from Western Canada to the U.S. and other international markets. Although certain pipeline and other transportation and export projects have been announced or are underway, many proposed projects have been cancelled or delayed due to regulatory hurdles, court challenges and economic and other socio-political factors. Due in part to growing production and a lack of new and expanded pipeline and rail infrastructure capacity, producers in Western Canada have experienced low commodity pricing relative to other markets in the last several years.

Pipelines

Producers negotiate with pipeline operators to transport their products to market on a firm, spot or interruptible basis depending on the specific pipeline and the specific substance. Transportation availability is highly variable across different jurisdictions and regions. This variability can determine the nature of transportation commitments available, the number of potential customers and the price received.

Under the Canadian Constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and, under the CERA, new interprovincial and international pipelines will require a federal regulatory review and Cabinet approval before they can proceed. However, recent years have seen a perceived lack of policy and regulatory certainty such that, even when projects are approved they often face delays due to actions taken by provincial and municipal governments, public interest groups and 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 petroleum and natural gas industry has experienced significant difficulty expanding the existing network of transportation infrastructure for crude oil, NGLs and natural gas, 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.

Specific Pipeline Updates

With respect to the current state of the transportation and exportation of crude oil from Western Canada to domestic and international markets, the Enbridge Inc's ("**Enbridge**") Line 3 Replacement Project (the "**Line 3 Replacement**") from Hardisty, Alberta, to Superior, Wisconsin, previously expected to be in-service in late 2019, experienced permitting difficulties in the United States and completion of the United States portion of the pipeline replacement was delayed following the announcement that the Minnesota Pollution Control Agency would require a public hearing concerning a key water permit. In June 2021, the Minnesota Court of Appeals declared that the Minnesota Utilities Commission correctly granted Enbridge a certificate of need and a pipeline routing permit for the final segment of the Line 3 Replacement. The Minnesota Supreme Court refused to hear an appeal on this matter.

After more than eight years, on September 29, 2021 Enbridge announced the completion of the 542 km Minnesota segment of the Line 3 Replacement. The Line 3 Replacement's in-service date was October 1, 2021 and is expected to transport 760,000 barrels per day at full capacity. In October 2022, a Minnesota

District Court upheld approvals given to the Line 3 Replacement, which were challenged on the basis that the U.S. Army Corps of Engineers should have taken into consideration how the broader project would impact climate change. The U.S. Army Corps of Engineers limited their environmental review of the project only to the impacts of construction in Minnesota rather than downstream concerns like greenhouse gas ("**GHG**") emissions from the ultimate burning of the crude oil carried in the pipeline.

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of political opposition in British Columbia, the federal government completed a purchase of the Trans Mountain Pipeline from Kinder Morgan Cochin ULC in August 2018. However, the Trans Mountain Pipeline expansion experienced a setback when, in August 2018, the Federal Court of Appeal identified deficiencies in the NEB's environmental assessment and the federal government's Indigenous consultations. The Federal Court of Appeal quashed the approval and directed Cabinet to correct these deficiencies. Following a reconsideration by the NEB and enhanced consultation efforts led by the federal government, Cabinet reapproved the Trans Mountain Pipeline expansion. Subsequent challenges to the approval were rejected by the Federal Court of Appeal in February 2020 and the Supreme Court of Canada ("**SCC**") in July 2020.

In addition, on April 25, 2018, the Government of British Columbia submitted a reference question to the British Columbia Court of Appeal, asking whether it has the constitutional jurisdiction to amend the Environmental Management Act to impose a permitting requirement on carriers of heavy crude within British Columbia. The British Columbia Court of Appeal unanimously answered the reference question in the negative. On January 16, 2020, the SCC unanimously dismissed the Attorney General of British Columbia's appeal.

Construction commenced on the Trans Mountain Pipeline expansion in late 2019 and it is expected to be in service in the third quarter of 2023, an extension from Trans Mountain's December 2022 estimate. The budget increase and in-service date delay have been attributed to, among other things, the ongoing effects of the COVID-19 pandemic and the widespread flooding in British Columbia in late 2021.

TC Energy Corporation's ("**TC Energy**") Keystone XL Pipeline was expected to begin construction in the first half of 2019, but pre-construction work was halted in late 2018 when a United States Federal Court Judge determined the underlying environmental review was inadequate. The United States Department of State issued its final Supplemental Environmental Impact Statement in late 2019, and in January 2020, the United States Government announced its approval of a right-of-way that would allow the Keystone XL Pipeline to cross 74 kilometers of federal land. On March 31, 2020, TC Energy announced it would proceed with the Keystone XL Pipeline. TC Energy also announced that the Government of Alberta had made a US $1.1 billion equity investment in the project and would guarantee a US $4.2 billion project level credit facility.

While construction on the Keystone XL Pipeline started in April 2020, the Keystone XL Pipeline remained subject to legal and regulatory barriers in the United States. In December 2019, a federal judge in Montana rejected the United States Government's request to dismiss a lawsuit by Native American tribes attempting to block certain permits and on April 15, 2020, a Montana judge ruled against the U.S. Army Corps of Engineers' use of a national permit for water crossings in the United States (Nationwide Permit 12). The United States Court of Appeals for the Ninth Circuit refused to stay the ruling. While the Supreme Court of the United States subsequently reinstated Nationwide Permit 12 in July 2020, it determined that the reinstatement would not apply to the Keystone XL Pipeline.

On January 20, 2021, Mr. Joseph Biden was sworn in as the 46th President of the United States, following which the Biden administration announced its decision to revoke the federal permit granted by the previous administration for the Keystone XL Pipeline, which has overturned a comprehensive regulatory process that lasted more than a decade. As a result of the revocation and following a comprehensive assessment of its options and consulting with its partners and stakeholders, including the Government of Alberta, on June 9, 2021, TC Energy terminated the Keystone XL Pipeline project.

Marine Tankers

Bill C-48 received royal assent on June 21, 2019, enacting the *Oil Tanker Moratorium Act*, which imposes a ban on tanker traffic transporting certain crude oil and NGLs or persistent crude oil products in excess of 12,500 metric tonnes along British Columbia's north coast. The ban may prevent pipelines from being built to, and export terminals from being located on, the portion of the British Columbia coast subject to the moratorium. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Federal*".

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). As of February 2023, no permanent rules have been approved.

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 infrastructure 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 is generally lower than the price received in other North American markets.

Required repairs or upgrades to existing pipeline systems in Western Canada have also led to further reduced capacity and apportionment of access, the effects of which have been exacerbated by storage limitations. However, in September 2019, the CER approved a policy change by TC Energy on its NOVA Gas Transmission Ltd. pipeline network (the "**NGTL System**") to prioritize deliveries into storage (the "**Temporary Service Protocol**"). The change has served to somewhat stabilize supply and pricing, particularly during periods of maintenance on the system. An expansion to the NGTL System was recommended for approval by the CER which was sent to the federal Cabinet for approval. On April 30, 2021, the Governor in Council approved the issuance of the certificate of public convenience by the CER.

In July 2020, the Explorers and Producers Association of Canada applied to extend the Temporary Service Protocol, which was opposed by NGTL and ultimately denied by the CER in February 2021.

In January 2022, the CER issued its decision denying NGTL's application for a proposed firm transportation linked service from receipt points along the North Montney Mainline in Northeast British Columbia to the proposed Willow Valley Interconnect delivery point. In its decision the CER stated the tolling methodology proposed would result in unjust and unreasonable tolls.

Specific Pipeline and Proposed LNG Export Terminal Updates

While a number of LNG export plants have been proposed in Canada, regulatory and legal uncertainty, opposition from environmental and Indigenous groups and changing market conditions have resulted in the cancellation or delay of many of these projects. Nonetheless, in October 2018, the joint venture partners of the LNG Canada LNG export terminal announced a positive final investment decision. Once complete, the project will allow LNG Canada to transport natural gas from northeastern British Columbia to the LNG Canada liquefaction facility and export terminal in Kitimat, British Columbia via the Coastal GasLink pipeline (the "**CGL Pipeline**"). The CGL Pipeline is being built by TC Energy. Pre-construction activities began in November 2018, with a completion target of 2025. In May 2020, TC Energy sold its 65% equity interest in the CGL Pipeline to investment companies KKR & Co Inc. and Alberta Investment Management Corporation while remaining the pipeline operator. Despite its approval, the CGL Pipeline has faced intense legal and social opposition. For example, protests involving the Hereditary Chiefs of the Wet'suwet'en First Nation and their supporters have caused delays to construction activities on the CGL Pipeline, although construction is proceeding. The CGL Pipeline is currently 80% complete and is slated to have a mechanical in-service date by the end of 2023.

In December 2019, the GER approved a 40-year export licence for the Kitimat LNG project (the "**Woodfibre LNG Project**"), a proposed joint venture between Chevron Canada Limited and Woodside Energy International (Canada) Limited, a subsidiary of Woodside Petroleum Ltd. However, both partners are looking to sell some or all of their interest in the project. Both parties elected to cease funding further feasibility work for the proposed Woodfibre LNG Project with both parties exiting the project. The Woodfibre LNG Project is a small-scale LNG processing and export facility near Squamish, British Columbia. As of July 2022, Pacific Energy Corporation Limited and Enbridge entered into a partnership agreement, pursuant to which they have agreed to jointly invest in the construction and operation of the Woodfibre LNG Project. The BC Oil and Gas Commission approved a project permit for the Woodfibre LNG Project in July 2019. In April 2022, a Notice to Proceed was issued, instructing the contractor to begin the work required to move the project toward major construction commencement in 2023. The Woodfibre LNG Project is expected to be substantially completed in Q3 2027. In November 2022, certain amendments to the conditions listed in the Impact Assessment Agency of Canada's decision statement for the project were proposed, which were made available for public comment until December 2022.

GNL Québec Inc., the proponent of the Énergie Saguenay Project, is currently working its way through a federal impact assessment process for the construction and operation of an LNG facility and export terminal located on Saguenay Fjord, an inlet which feeds into the St. Lawrence River in Québec. The Énergie Saguenay Project is currently slated for completion in 2026. Pieridae Energy Ltd.'s ("**Pieridae**") proposed Goldboro LNG project, located in Nova Scotia, would see LNG exported from Canada to European markets. Pieridae has a downstream agreement with Uniper, a German utility company, for all of the LNG produced at Goldboro's train. The federal government has issued Goldboro LNG a 20-year export licence, but Pieridae decided in July 2021, not to proceed with the project.

Cedar LNG Export Development Ltd.'s Cedar LNG Project near Kitimat, British Columbia, is currently in the environmental assessment stage, with British Columbia's Environmental Assessment Office ("**BC EAO**") conducting the environmental assessment on behalf of the Impact Assessment Agency of Canada ("**IA Agency**"). On June 8, 2021, the Haisla First Nation and Pembina Pipeline Corporation announced a partnership agreement whereby Pembina Pipeline Corporation would become the Haisla Nation's partner in the development of the Cedar LNG Project. The BC EAO completed its assessment of the application for an Environmental Assessment Certificate in November 2022. The project has been referred to provincial decision makers and provided to the federal Minister of the Environment and Climate Change to inform the federal decision. Ksi Lisims LNG project, owned by Nisga's Lisims Government, Rockies LNG Partners and Western LNG is currently in the environmental assessment stage, with the BC EAO conducting the environmental assessment on behalf of the IA Agency. Construction is anticipated to begin in 2024 with the site to be operational in late 2027 or 2028.

Enbridge Open Season

In August 2019, Enbridge initiated an open season for the Enbridge mainline system, which has historically operated as a common carrier pipeline system transporting crude oil. The changes that Enbridge wished to implement included the transition of the mainline system from a common carrier to a primarily contract carrier pipeline, wherein shippers will have to commit to reserved space in the pipeline for a fixed term, with only 10% of available capacity reserved for nominations.

Several shippers challenged Enbridge's open season and, in particular, Enbridge's ability to engage in an open season without first obtaining prior regulatory approval to implement a contract carriage model. Following an expedited hearing process, the CER decided to shut down the open season, citing concerns about fairness and uncertainty regarding the ultimate terms and conditions of service. On December 19, 2019, Enbridge applied to the CER for approval of the proposed service and tolling framework. On November 26, 2021, the CER issued its Reasons for Decision in Enbridge Pipelines Inc. RH-001-2020, denying the application to introduce firm service on the Canadian Mainline. If approved, the application would have made 90% of the Canadian Mainline's currently uncommitted capacity subject to firm contracts for priority access, with contract terms ranging from eight to 20 years. Contracts for firm service were to be awarded through an open season process put forward as part of the application.

The United States Mexico Canada Agreement and Other Trade Agreements

NAFTA / USMCA

On July 1, 2020, the North American Free Trade Agreement ("**NAFTA**"), a free trade agreement among the governments of Canada, the United States and Mexico, was replaced by a new trade agreement, widely referred to as the United States Mexico Canada Agreement ("**USMCA**"), and sometimes referred to as the Canada United States Mexico Agreement ("**CUSMA**"). As the United States remains Canada's primary trading partner and the largest international market for the export of crude oil, NGLs and natural gas from Canada, the implementation of the USMCA could have an impact on Western Canada's petroleum and natural gas industry at large, including the Corporation'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 and ten other countries recently concluded discussions and agreed on the draft text of the Comprehensive and Progressive Agreement for Trans-Pacific Partnership ("**CPTPP**"), which is intended to allow for preferential market access among the countries that are parties to the CPTPP. The CPTPP is in force among the first seven countries to ratify the agreement: Canada, Australia, Japan, Mexico, New Zealand, Vietnam and Singapore.

Canada has also pursued a number of other international free trade agreements with 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, which received royal assent on March 17, 2021. 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.

While it is uncertain what effect CETA, CPTPP, CUKTCA or any other trade agreements will have on the oil and gas industry in Canada, the lack of available infrastructure for the offshore export of oil and gas may limit the ability of Canadian oil and gas producers to benefit from such trade agreements.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments (i.e. the Crown). Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. The provincial governments in Western Canada's provinces conduct regular land sales where crude oil and natural gas companies bid for leases to explore for and produce crude oil and natural gas pursuant to mineral rights owned by the respective provincial governments. The leases generally have a fixed term; however, a lease may generally be continued after the initial term where certain minimum thresholds of production have been reached, all lease rental payments have been paid on time and other conditions are satisfied.

To develop crude oil and natural gas resources, it is necessary for the mineral rights owner to have access to the surface lands as well. Each province has developed its own process for obtaining surface access to conduct operations that operators must follow throughout the lifespan of a well, including notification requirements and providing compensation for affected persons for lost land use and surface damage. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Each of the provinces in Western Canada have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license. In addition, Alberta has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. British Columbia has a policy of "zone specific retention" that allows a lessee to continue a lease for zones in which they can demonstrate the presence of oil or natural gas, with the remainder reverting to the Crown. Such reversionary rights may impact any gross overriding royalty interests ("**GORR Interests**") granted out of Crown leases.

In addition to Crown ownership of the rights to crude oil and natural gas, private ownership of crude oil and natural gas (i.e. freehold mineral lands) also exists in Western Canada. In the provinces of Alberta, British Columbia, Saskatchewan and Manitoba approximately 19%, 6%, 20% and 80%, respectively, of the mineral rights are owned by the federal government on behalf of First Nations or national parks and by private freehold owners, such as the Corporation. Rights to explore for and produce privately owned crude oil and natural gas are granted by a lease or other contract on such terms and conditions as may be negotiated between the owner of such mineral rights and companies seeking to explore for and/or develop crude oil and natural gas reserves.

An additional category of mineral rights ownership includes ownership by the Canadian Federal Government of some legacy mineral lands and within Indigenous reservations designated under the *Indian Act* (Canada). Indian Oil and Gas Canada ("**IOGC**"), which is a federal government agency, manages subsurface and surface leases, in consultation with the applicable Indigenous peoples, for the exploration and production of crude oil and natural gas on Indigenous reservations.

Until recently, crude oil and natural gas activities conducted on Indian reserve lands were governed by the Indian Oil and Gas Act (the "**IOGA**") and the Indian Oil and Gas Regulations, 1995 (the "**1995 Regulations**"). In 2009, Parliament passed An Act to Amend the Indian Oil and Gas Act, amending and modernizing the IOGA (the "**Modernized IOGA**"), however the amendments were delayed until the federal government was able to complete stakeholder consultations and update the accompanying regulations (the "**2019 Regulations**"). The Modernized IOGA and the 2019 Regulations came into force on August 1, 2019.

The GORR Interests are royalty interests that are granted or carved out of leasehold interests (created through the issuance of a lease by the Crown or fee simple mineral title owner). As such, the continued existence and value of the GORR Interests is dependent upon the validity and terms of the leasehold interest out of which they were granted.

In respect of the GORR Interests granted out of Crown leases, in addition to the varying terms and conditions set forth in provincial legislation, as discussed above, the provinces of Alberta, British Columbia, Saskatchewan and Manitoba have implemented legislation providing for the reversion to the Crown of mineral rights to non-productive geological formations at the conclusion of the primary term of a lease or licence.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates and other matters. The royalty regime in a given province is in addition to applicable federal and provincial taxes and is a significant factor in the profitability of crude oil, NGLs, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of production. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests or net carried interests.

Occasionally the governments of the western Canadian provinces have established incentive programs for exploration and development. Such programs often provide for volume-based incentive programs, royalty rate reductions, royalty holidays or royalty tax credits and may be introduced when commodity prices are low. The incentive programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. In addition, incentive programs may be introduced to encourage producers to prioritize certain kinds of development or undertake initiatives using new technologies that may enhance or improve recovery of crude oil, NGLs and natural gas, or improve environmental performance.

The federal government also creates incentives and other financial aid programs intended to assist businesses operating in the petroleum and natural gas industry. Recently, these programs, including, but not limited to, programs that provide direct financial support to companies operating in the petroleum and natural gas industry and/or targeted funding for various initiatives related to industry diversification and environmental matters, including those programs created in response to the COVID-19 pandemic, have been administered through federal agencies such as the Business Development Bank of Canada, Natural Resources Canada, Export Development Canada, and Innovation, Science and Economic Development Canada.

Producers and working interest owners of oil and natural gas rights may also create additional royalties or royalty-like interests through non-public transactions, which include the creation of instruments such as overriding royalties, net profits interests and net carried interests, the terms of which are subject to negotiation.

Alberta

In Alberta, provincially set royalty rates apply to Crown-owned mineral rights and crude oil and natural gas producers are responsible for calculating their royalty rate on an ongoing basis.

In 2016, the Government of Alberta adopted a modernized Crown royalty framework (the "**Modernized Framework**") that applies to all conventional oil (i.e. not oil sands) and natural gas wells drilled after December 31, 2016 that produce Crown-owned resources. The previous royalty framework (the "**Old Framework**") will continue to apply to wells producing Crown-owned resources that were drilled prior to January 1, 2017 until December 31, 2026. As of January 1, 2027, these older wells will become subject to the Modernized Framework. The Royalty Guarantee Act (Alberta), which came into effect on July 18, 2019, provides that no major changes will be made to the current crude oil and natural gas royalty structure for a period of at least 10 years.

Royalties on production from non-oil sands wells under the Modernized Framework are determined on a "revenue-minus-costs" basis. The cost component is based on a Drilling and Completion Cost Allowance formula that relies, in part, on the industry's average drilling and completion costs, determined annually by the AER, and incorporates information specific to each well such as vertical depth and lateral length.

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 at a royalty rate between 5% and 40% for crude oil and pentanes and 5% and 36% for methane, ethane, propane and butane, all 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 and operates on a sliding scale. 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 towards a minimum rate of 5% 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.

Crude oil and natural gas producers are responsible for calculating their royalty rate on an ongoing basis. The Crown's royalty share of production is payable monthly and producers must submit their records showing the royalty calculation. The Mines and Minerals Act (Alberta) was amended in 2014 to shorten the window during which producers can submit amendments to their royalty calculations before they become statute-barred, from four years to three years.

Subject to certain available incentives, royalty rates for conventional crude oil production subject to the Old Framework range from a base rate of 0% to a cap of 40%; royalty rates for natural gas production under the Old Framework range from a base rate of 5% to a cap of 36%. The Old Framework also includes a natural gas royalty formula which provides for a reduction based on the measured depth of the well below 2,000 meters deep, as well as the acid gas content of the produced gas. Under the Old Framework, the royalty rate applicable to NGL is a flat rate of 40% for pentanes and 30% for butanes and propane.

Oil sands production is also subject to Alberta's royalty regime. The Modernized Framework does not impact or change the oil sands royalty framework. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1% and 9% depending on the market price of crude oil, determined using the average monthly price, expressed in Canadian dollars, for West Texas Intermediate crude oil at Cushing, Oklahoma. Rates are 1% when the market price of crude oil is less than or equal to $55/bbl and increase for every dollar by which the market price of crude oil increases to a maximum of 9% when crude oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of between 1% and 9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar by which the market price of crude oil increases above $55/bbl to a maximum of 40% when crude oil is priced at $120/bbl or higher. The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage crude oil and natural gas development and new drilling. In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources, including as applied to coalbed methane wells, shale gas wells and horizontal crude oil and natural gas wells. In addition to royalties, producers of crude oil and natural gas from Crown lands in Alberta are also required to pay annual rental payments at a rate of $3.50 per hectare.

Royalty rates for the production of privately-owned crude oil and natural gas are negotiated between the producer and the resource owner.

Freehold Mineral Taxes are levied annually for production from freehold mineral lands. On average, the tax levied in Alberta is 4% of revenues reported from freehold mineral title properties. Freehold Mineral Taxes are in addition to any other negotiated royalty or other payment required to be paid to the owner of such freehold mineral rights.

Saskatchewan

In Saskatchewan, the Crown owns approximately 80% of the oil and gas rights, with the remainder being freehold lands. For the Crown lands, taxes (the "**Resource Surcharge**") and royalties are applicable to revenue generated by corporations focused on oil and gas operations. Crown royalties payable on the production of crude oil and natural gas are paid on a well-by-well basis. Producers of crude oil and natural gas receive royalty invoices from the Government of Saskatchewan on a monthly basis. The Resource Surcharge rate is 3% of the value of sales of all crude oil and natural gas produced from wells drilled in Saskatchewan prior to October 1, 2002. For crude oil and natural gas produced from wells drilled in Saskatchewan after September 30, 2002, the Resource Surcharge rate is 1.7% of the value of sales. Additionally, a mineral rights acreage tax is charged to mineral rights holders paid on an annual basis at the rate of $1.50 per acre owned regardless of whether or not there is production from the lands.

In addition to such surcharges and taxes, the Crown royalty rate payable in respect of crude oil, depends on a number of variables including, the type and vintage of crude oil, the quantity of crude oil produced in a month, the average wellhead price and certain price adjustment factors determined monthly by the provincial government. This means that producers may pay varying royalties each month, depending on monthly production, governmental price adjustments and the underlying characteristics of the producer's assets. Where production equals the relevant reference well production rate, the minimum Crown royalty rate payable ranges from 5% to 20% and the maximum royalty rate payable ranges from 30% to 45%, depending on the classification of the crude oil, the average wellhead price and subject to applicable deductions.

The amount payable as a Crown royalty in respect of production of natural gas and NGLs is determined by a sliding scale based on the monthly provincial average gas price published by the Government of Saskatchewan, the quantity produced in a given month, the type of natural gas, the classification of the natural gas and the finished drilling date of the respective well. Similar to crude oil royalties, the royalties payable on natural gas will range from 5% to 20%, and additional marginal royalty rates may apply between 30% to 45%, where average wellhead prices are above base prices. Again, this means that producers may pay varying royalties each month, depending on pricing factors, governmental adjustments and the underlying characteristics of the producer's assets.

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, with targeted programs in effect for certain vertical crude oil wells, exploratory gas wells, horizontal crude oil and natural gas wells, enhanced crude oil recovery wells and high water-cut crude oil wells. As of April 1, 2021, on associated gas produced from wells other than gas wells, including natural gas produced from oil wells, the Minister of Energy and

Resources implemented a five-year Associated Gas Royalty Moratorium on the collection of Crown Royalty and Freehold Production Tax. The moratorium is in connection with the Government of Saskatchewan's Growth Plan and is aimed at meeting the Government of Saskatchewan's regulatory obligations to reduce methane-based GHG emissions by 40% to 45% between 2020 and 2025. The Associated Gas Royalty Moratorium is applicable to natural gas produced on or after April 1, 2021 and before April 1, 2026.

The Government of Saskatchewan also has a drilling incentive whereby qualifying incentive volumes of newly drilled oil wells are subject to a maximum royalty rate of 2.5% for Crown production and a maximum production tax rate of 0% for freehold production.

Royalty rates for the production of privately-owned crude oil and natural gas are negotiated between the producer and the resource owner. In addition, producers must pay a freehold production tax, determined by first establishing the Crown royalty rate, and then subtracting a calculated production tax factor that depends on the classification of the petroleum substance produced.

Freehold and Other Types of Non-Crown Land Royalties and Taxes

Royalties on production from privately-owned freehold lands are negotiated between the mineral freehold owner and the lessee under a negotiated lease or other contract. Producers and working interest participants may also pay additional royalties to parties other than the freehold mineral owner where such royalties are negotiated through private transactions.

In addition to the royalties payable to the mineral owners (or to other royalty holders if applicable), Freehold Mineral Taxes or production taxes are levied on the production of crude oil and natural gas from freehold lands in each of the Western Canadian provinces where the Crown does not hold the mineral rights. A description of the Freehold Mineral Taxes payable in each of the Western Canadian provinces is included in the above descriptions of the royalty regimes in such provinces.

Where crude oil and natural gas leases fall under the jurisdiction of the IOGC, the IOGC is responsible for issuing crude oil and natural gas agreements between Indigenous groups and producers and collecting and distributing royalty revenues. The exact terms and conditions of each crude oil and natural gas lease dictate the calculation of royalties owed, which may vary depending on the involvement of the specific Indigenous group. Ultimately, the relevant Indigenous group must approve the royalty rate for each lease.

Production and Operation Regulations

The oil and natural gas industry in Canada is highly regulated and subject to significant control by provincial regulators. Regulatory approval is required for, among other things, the drilling of oil and natural gas wells, construction and operation of facilities, the storage, injection and disposal of substances and the abandonment and reclamation of well-sites. In order to conduct oil and gas operations and remain in good standing with the applicable provincial regulator, Lycos must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance with such legislation, regulations, orders, directives or other directions can be costly and a breach of the same may result in fines or other sanctions.

Regulatory Authorities and Environmental Regulation

The Canadian oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well, facility and pipeline sites. Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in suspension or revocation of necessary licences and authorizations, civil liability and the imposition of material fines and penalties.

In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and GHG emissions (typically measured in terms of their global warming potential and expressed in terms of carbon dioxide equivalents ("**CO2e**"), may impose further requirements on operators and other companies in the petroleum and natural gas industry).

Federal

Canadian environmental regulation is the responsibility of the federal government 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, however, such conflicts are uncommon. The federal government has primary jurisdiction over federal works, undertakings and federally regulated industries such as railways, aviation and interprovincial transport. The CERA and the *Canadian Environmental Assessment Act, 201*2 ("**CEAA**") provide the foundation for the federal government to protect the environment and cooperate with provinces to do the same.

On August 28, 2019, with the passing of Bill C-69, the CERA and the IAA came into force and the NEB Act and the CEAA were repealed. As part of the regulatory transition, the IA Agency replaced the Canadian Environmental Assessment Agency ("**CEA Agency**").

The enactment of the CERA and IAA introduced a number of important changes to the regulation of federally regulated major projects and their associated environmental assessments. Previously, the NEB administered its statutory jurisdiction as an integrated regulatory body. However, the CERA separates the CER's administrative and adjudicative functions. A board of directors and a chief executive officer will manage strategic, administrative and policy considerations while adjudicative functions fall to independent commissioners. Despite this structural change, the CER has assumed the jurisdiction previously held by the NEB over matters such as the environmental and economic regulation of pipelines, transmission infrastructure and offshore renewable energy projects, including offshore wind and tidal facilities. In its adjudicative role, the CERA tasks the CER with reviewing applications for the development, construction and operation of these projects, culminating in their eventual abandonment.

The IAA is similar to the repealed CEAA 2012 in that it 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 IA Agency or, in the case of certain pipelines, a joint review panel comprised of members from the CER and the IAA. 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 socioeconomic factors, climate change and impacts to Indigenous rights. It also requires an expanded public interest assessment, including Indigenous consultation, as applicable. The impact assessment must look at the direct result of the project's construction and operation. Designated projects specific to the petroleum and natural gas industry include pipelines that require more than 75 km of new right 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. The Government of Alberta has submitted a reference question to the Alberta Court of Appeal regarding the constitutionality of the IAA. On May 10, 2022, the Alberta Court of Appeal released its opinion stating that the IAA went beyond the federal Parliament's constitutional authority and reached into areas of exclusive provincial authority. The federal Government has appealed the Alberta Court of Appeal's opinion to the Supreme Court of Canada. A date for arguments has not been scheduled, but filing deadlines have been set for early 2023.

On June 21, 2021, the United Nations Declaration on the Rights of Indigenous Peoples Act received Royal Assent and immediately came into force. Bill C-15 is the Government of Canada's response to requests to implement the United Nations Declaration of the Rights of Indigenous Peoples as a framework for reconciliation in Canada.

Alberta

The discharge of crude oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require Lycos to incur costs to remedy such discharge in the event that they are not covered by the Corporation's insurance. Although the Corporation maintains insurance to industry standards, which in part covers liabilities associated with discharges, it is not certain that such insurance will cover all possible environmental events, foreseeable or otherwise, or whether changing regulatory requirements or emerging jurisprudence may render such insurance of little benefit. In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and GHG emissions, may impose further requirements on operators and other companies in the oil and natural gas industry.

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

The 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 Alberta Environment and Protected Areas (previously known as the Ministry of Environment and Parks), the Alberta Ministry of Energy, the Policy Management Office, 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 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, increased seismicity 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 crude oil and natural gas production. 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 crude oil and natural gas producers working in certain areas where the likelihood of increased seismic activity 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**"). Crude 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 crude 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 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.

Saskatchewan

The Saskatchewan Ministry of Energy and Resources is the primary regulator of crude oil and natural gas activities in the province. The Oil and Gas Conservation Act ("**SKOGCA**") is the act governing the regulation of resource development operations in the province, along with The Oil and Gas Conservation Regulations, 2012 and The Petroleum Registry and Electronic Documents Regulations. The Government of Saskatchewan has implemented a number of operational requirements, including the increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers, and procedural requirements including those related to Saskatchewan's participation as partner in the Petrinex Database.

The environmental scheme in Saskatchewan is governed by *The Environmental Management and Protection Act, 2010* and *The Forest Resources Management Act.* In Saskatchewan, the ministry has adopted a results-based regulatory model which largely leaves the determination of how environmental protection is to be achieved with the respective proponent.

Liability Management Rating Programs

Alberta

The AER oversees liability management in the province. On June 30, 2020, the Government of Alberta announced a new Liability Management Framework ("**AB LMF**") that will replace the Alberta Liability Management Program ("**AB LMR Program**") and its constituent programs. The goal of the AB LMF is to implement a holistic and full lifecycle approach to reclamation and remediation obligations. Since the announcement, the Government of Alberta has gradually begun to phase-in the AB LMF through legislative and AER directive amendments. New developments under the AB LMF 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**").

The announcement and implementation of the AB LMF and the desire to rethink liability management in Alberta follows the SCC's decision in Orphan Well Association v Grant Thornton Ltd. (also known as the Redwater decision). As a result of the Redwater decision, receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licencees or to require a licencee to pay a security deposit before approving a transfer when such a licencee 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 Bill 12: The Liabilities Management Statutes Amendment Act (the "**LMSAA**") which came into force on proclamation. The LMSAA places the burden of a defunct licensees' abandonment and reclamation obligations first on the defunct licencee's working interest partners, and second, the AER may order the orphan fund (the

"**Orphan Fund**") to assume care and custody and accelerate the clean-up of wells or sites which do not have a responsible owner.

Alberta's OGCA established an Orphan Fund which is run by the Orphan Well Association ("**OWA**") to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline if a licencee or working interest participant becomes insolvent or is unable to meet its obligations. The Orphan Fund was originally conceived to be bankrolled exclusively by licencees in the former Licensee Liability Rating Program (the "**LLR Program**") and Alberta Oilfield Waste Liability Program (the "**AB OWL Program**") who contributed to a levy administered by the AER. However, the Government of Alberta has loaned the Orphan Fund approximately $335 million. The Government also covered $113 million in levy payments that licencees 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. Collectively, these programs were designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licencees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. Under the new AB LMF, the OWA has broader authority to assist in the reclamation and remediation of wells, facilities or pipelines.

The AB LMR Program previously governed most conventional upstream crude oil and natural gas wells, facilities and pipelines. It consisted of three distinct programs: the AB LLR Program, the AB OWL Program and/or the Large Facility Liability Management Program.

Following the Redwater decision, Alberta has committed to actively reducing inventories of orphan and inactive well sites in the province. It is the goal that the AB LMF will assist in addressing the OWA's inventory, creating a framework and regulatory scheme that will better manage site reclamation throughout the lifecycle of a project. The AB LMF is to address five key components supporting a lifecycle approach to liability management: (i) practical guidance and support for distressed operators; (ii) licencee capability assessment system to provide proactive support through ongoing financial capability review; (iii) mandatory spend targets to support inventory reduction; (iv) a process to address legacy and post-closure sites or sites that were remediated, reclaimed or abandoned prior to the AB LMF; and (v) the OWA taking on a more involved role in managing clean-up of oil and natural gas facilities and infrastructure. On December 1, 2021, the Government of Alberta announced amendments to Directive 006: Licensee Liability Rating ("**LLR**") Program and a new Directive 008: Licensee Life- Cycle Management. A new Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals was also introduced in April 2021 which introduces new criteria for the AER to consider whether an applicant, licencee or approval holder poses an "unreasonable risk". Among other changes under the AB LMF, the AB LLR Program will be replaced with the Licensee Capability Assessment System, which is intended to be a more comprehensive assessment of corporate health and will consider a wider variety of factors than those considered under the AB LLR Program and will establish clear expectations for industry with regards to the management of liabilities throughout the entire lifecycle of crude oil and natural gas projects. Importantly, the AB LMF will also provide proactive support to distressed operators and will require companies operating in Alberta's petroleum and natural gas industry to make mandatory annual minimum payments towards outstanding reclamation obligations in accordance with five-year rolling spending targets. Under the AB LMF each licencee will be required to meet mandatory annual spend targets for well closures and abandonments. During the summer of 2022, the AER announced it would increase spend targets for liabilities in 2023 from $422 million to $700 million and released forecasted targets through 2027, each of which are expected to increase annually by 9%.

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 AER in 2015 also implemented the Inactive Well Compliance Program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under Directive 013: Suspension Requirements for Wells ("**Directive 013**"). The IWCP applied to all inactive wells that were noncompliant with Directive 013 as of April 1, 2015. The objective was to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within five years. As of April 1, 2015, each licencee was required to bring 20% of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with Directive 020: Well Abandonment. The compliance deadline for the final year of the IWCP was extended from April 1, 2020 to September 1, 2020 and was concluded in March of 2021.

As part of its strategy to encourage the decommissioning, remediation and reclamation of inactive or marginal crude oil and natural gas infrastructure, the AER announced a voluntary area-based closure ("**ABC**") program in 2018. The ABC program is designed to reduce the cost of abandonment and reclamation operations through industry collaboration and economies of scale. Participants seeking to participate in the program must commit to an inactive liability reduction target to be met through closure work of inactive assets. The ABC, together with the inventory reduction program implemented under the AB LMF, which implements mandatory closure spend targets over a five-year rolling period, will enable companies to work together to share the costs of cleaning up multiple sites in one area.

The mix between active programs under the AB LMF and the AB LMR Program highlights the transitional and dynamic nature of liability management in Alberta. While the province is moving towards the AB LMF 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.

Saskatchewan

In Saskatchewan, the Ministry of Economy implements the Saskatchewan Licensee Liability Rating Program (the "**SK LLR Program**"). The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to an orphan fund (the "**Oil and Gas Orphan Fund**") established under the SKOGCA. The Oil and Gas Orphan Fund takes on the obligation of carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when a licensee or WIP is defunct or missing. The SK LLR Program requires all new licensees to submit a $10,000 non-refundable Orphan Fund fee in order to be deemed eligible to transfer licences, and all licensees whose deemed liabilities exceed their deemed assets (i.e., an LLR of below 1.0) are required to post a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month for all licensees of oil, gas and service wells and upstream oil and gas facilities and this data is publicly available. On August 19, 2016, the Ministry of the Economy released a notice to all operators introducing interim measures in response to Redwater. Among other things, the Ministry announced that it considers all licence transfer applications non-routine as the Ministry does not strictly rely on the standard LMR calculation in evaluating deposit requirements, and that further changes may be forthcoming.

In February 2021, the Energy Regulation Division of the Ministry of Energy and Resources announced that it was consulting with stakeholders on proposed regulatory enhancements intended to strengthen Saskatchewan's oil and gas liability management framework and reduce the prospect of new orphan oil and gas wells and facilities in Saskatchewan. This process led to the development of the new Financial Security and Site Closure Regulations (the "**Closure Regulations**"), which were published in June 2021, but are not yet in force. Changes under the Closure Regulations will include: (i) changes to the formula for determining if a licensee poses a risk; (ii) annual spend targets for closure activities by licensees, commencing in 2023; and (iii) new guidance on when a security deposit may be required by a licensee or in connection with a transfer. The Oil and Gas Conservation Regulations, 2012, (the "**Conservation Regulations**") remain in effect until the Closure Regulations come into force. Among other things, the

Conservation Regulations provide a formula for determining a licensee's LLR, outline eligibility requirements for holding licences, and provide guidance on when a security deposit may be required by a licensee or in connection with a transfer.

Federal and Provincial Support for Liability Management

As part of an announcement of federal relief for Canada's petroleum and natural gas industry in response to COVID-19, the federal government pledged $1.72 billion to clean up orphan and inactive wells in Alberta, Saskatchewan and British Columbia. These funds were administered by regulatory authorities in each province and disbursed through various provincial programs. The majority of these funds have now been allocated and disbursed.

Climate Change Regulation

Climate change regulation at each of the international, federal and provincial levels has the potential to significantly affect the regulation of the oil and natural gas industry in Canada. These impacts are uncertain and it is not possible to predict the extent of future requirements. Any new laws and regulations (or additional requirements to existing laws and regulations) could have a material impact on the Corporation's operations and cash flow. An example of a change in policy that may impact the petroleum and natural gas industry is the International Maritime Organization's implementation of regulations that limit the sulphur content of marine fuel oil, reducing the permissible amount of sulphur from 3.5% to 0.5%, effective January 1, 2020.

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 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. On January 20, 2021, President Biden of the United States signed an executive order to rejoin the Paris Agreement. To date, 189 of the 197 parties to the UNFCCC have ratified the Paris Agreement, including Canada. In December 2019, the United Nations annual Conference of the Parties took place in Madrid, Spain. The Conference concluded with the attendees delaying decisions about a prospective carbon market and emissions cuts until the next climate conference. The result of the 2021 United Nations Climate Change Conference, more commonly referred to as COP26, was the Glasgow Climate Pact, negotiated through consensus of the representatives of the 197 attending parties. Owing to late interventions from India and China, which weakened a move to end coal power and fossil fuel subsidies, the conference ended with the adoption of a less stringent resolution than some anticipated. The Glasgow Climate Pact reaffirms the long-term global goals (including those in the Paris Agreement) to hold the increase in the global average temperature to below 2.0° Celsius above pre-industrial levels and to pursue efforts to limited the temperature increase to 1.5° Celsius above pre-industrial levels.

The Government of Canada has pledged to cut its emissions by 30% from 2005 levels by 2030; however, they have also indicated that they expect to implement policies to exceed this target. In connection with this target, 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. In March 2022, the Government of Canada also introduced Canada's 2030 Emissions Reduction Plan (the 2030 Reduction Plan), which provides the building blocks for the Canadian economy to achieve 40% to 45% emissions reductions below 2005 levels by 2030. The 2030 Reduction Plan includes $9.1 billion in new investments as well as carbon pricing and clean fuels measures to assist in growing economic opportunities for a clean future. Progress of the 2030 Reduction Plan will be reviewed and produced in reports in 2023, 2025 and 2027, with additional targets to be developed for 2035 and 2050.

On December 11, 2020, the Government of Canada released its Healthy Environment and a Healthy Economy Plan (the **"HEHE Plan**") which builds on the Pan-Canadian Framework and provides a road map forward to meet Canada's 2030 emissions reduction target. The HEHE Plan includes a $3-billion investment over five years to a Net-Zero Accelerator Fund to invest in projects to decarbonize large emitters, scale-up clean technology and otherwise accelerate industry transformation across all sectors. In addition, the HEHE Plan proposes to invest an additional $964 million over four years towards renewable energy and grid modernization projects and $300 million over five years to advance the use of clean and reliable energy in rural, remote and Indigenous communities. The third component of the HEHE Plan pertains to zero emission vehicles. This includes investing an additional $287 million to continue the federal government's Incentives for Zero-Emission Vehicles program until March 2022, $150 million over three years towards charging and refueling stations across Canada, and $1.5 billion towards a Low-Carbon and Zero-Emissions Fuels Fund to increase the production of low-carbon fuels.

Also of relevance to the petroleum and natural gas industry, in June 2022, the federal government introduced the Single-use Plastics Prohibitions Regulations ("**SUPPR**"). The SUPPR prohibits, subject to certain exemptions, the manufacture, import and sale of single-use plastic checkout bags, cutlery, foodservice ware made from or containing problematic plastics, ring carriers, stir sticks and straws. The prohibitions on manufacture and import for sale in Canada and sale and manufacture, import and sale for export come into force on a rolling basis between December 2022 and December 2025.

On November 19, 2020, the federal government announced Bill C-12, an Act respecting transparency and accountability in Canada's efforts to achieve net-zero greenhouse gas emissions by the year 2050. Canada joins over 120 countries in committing to net-zero emissions by 2050, including the UK, Germany, France and Japan. The Canadian Net-Zero Emissions accountability Act became law in June 2021 and legally binds the federal government to a process to achieve net-zero emissions by 2050. The legislation also sets rolling five-year emissions-reduction targets (starting in 2030) and requires emissions reduction plans to reach each target on a reporting basis and enshrine greater accountability and public transparency into Canada's plan for meeting net-zero emissions by 2050 by providing for independent third-party review by the Commissioner of the Environment and Sustainable Development.

On June 21, 2018, the federal government enacted the *Greenhouse Gas Pollution Pricing Act* (Canada), S.C. 2018, c. 12, s. 186 ("**GGPPA**"), which came into force on January 1, 2019. This regime has two parts: an output-based pricing system for large industry and a regulatory fuel charge imposing an initial price of $20/tonne of CO2e. This system applies in provinces and territories that request it and in those that do not have their own emissions pricing systems in place that meet the federal standards. The effect of the GGPPA is that, regardless of whether a particular province has enacted legislation of its own, there is a uniform price on emissions across the country.

In accordance with the HEHE Plan, the price on carbon is set to increase annually at a rate of $15/tonne of CO2e per year commencing in 2023 through to 2030. In August 2021, the federal government established strengthened minimum national standards for 2023 to 2030, which includes the requirement that all jurisdictions establish systems that align with the federal carbon pricing trajectory and benchmark requirements to 2030. Once in place, the systems will remain until 2027.

Alberta, Saskatchewan, Ontario and Manitoba each challenged the constitutionality of the GGPPA. In both the Saskatchewan and Ontario references, the appellate Courts ruled in favour of the constitutionality of the GGPPA; the Alberta Court of Appeal determined that the GGPPA is unconstitutional. All three judgments were appealed to the SCC and the hearing took place in September 2020. On March 25, 2021, the SCC released its decision in Reference re Greenhouse Gas Pollution Pricing Act, upholding the constitutionality of a federal law establishing minimum national standards for carbon pricing in Canada.

Manitoba also made an appeal to the Federal Court stating that the federal government did not act properly in imposing a minimum price on carbon because Manitoba was planning to use its own lower price. In October of 2021, the Federal Court rejected Manitoba's argument, stating that the federal government's actions were consistent with the purpose of the GGPPA as was upheld by the Supreme Court of Canada.

Following the Supreme Court's decision upholding the constitutionality of the GGPPA, any province or territory has the flexibility to design their own pricing system, so long as it meets the minimum national stringency standards or federal benchmarks. Currently, the Fuel Charge applies in each of Ontario, Manitoba, Yukon, Alberta, Saskatchewan and Nunavut, while the Output-Based Pricing System applies in Ontario (until December 31, 2021), Manitoba, Prince Edward Island, Yukon, Nunavut and partially in Saskatchewan. The provincial plans for each of Nova Scotia, Prince Edward Island and Newfoundland and Labrador were deemed by the federal government to have fallen short of the federal benchmark, making the federal OBPS applicable in each of those provinces as of July 1, 2023. For so long as the provincial systems in Alberta (under the *Technology Innovation and Emissions Reduction (TIER)* regulation) and Saskatchewan meet the federal stringency standards for the emissions they cover, these systems will continue to apply, with the backstop covering those emissions not covered by the provincial systems, as applicable.

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 petroleum and natural gas industry, and came into force on January 1, 2020. By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and the intentional venting of methane, as well as ensuring that crude 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 federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

As part of its efforts to provide relief to Canada's petroleum and natural gas industry in light of the COVID-19 pandemic, on October 29, 2020, the federal government launched the $750-million Emission Reduction Fund to reduce methane and GHG emissions. The fund will provide repayable funding to eligible onshore and offshore crude oil and natural gas companies to support investments to reduce GHG emissions by adopting greener technologies.

In October 2018, the federal government announced a pricing scheme as an alternative for large electricity generators to incentivize a reduction in emissions intensity, rather than encouraging a reduction in generation capacity.

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

The federal government announced that it will proceed with the development and implementation of a Clean Fuel Standard ("**CFS**") that will require producers, importers and distributors to reduce the emissions intensity of gaseous, liquid and solid fuels. On December 18, 2020, the federal government published proposed CFS regulations, with the Clean Fuel Regulations (CFS Regulations) coming into force on June 21, 2022. The CFS Regulations take a performance-based approach to reducing greenhouse gas emissions. The CFS Regulations require suppliers of liquid fuels, such as gasoline, diesel and kerosene to gradually reduce the amount of carbon in their product. Beginning in 2023, the carbon intensity reduction requirement will start at 3.5gCO2e/MJ, increasing by 1.5 gCO2e/MJ each year and reaching 14 gCO2e/MJ in 2030. The standard will apply to any company that domestically produces or imports at least 400 cubic metres of liquid fossil fuels for use in Canada. It is the goal of the program to incentivize innovation and adoption of clean technologies while giving fuel suppliers the ability to meet requirements in a cost-effective way that works for their business. The proposed regulations offer compliance credits, tracked via the Credit and Tracking System, and created a market to incentivize industries to innovate and adopt cleaner technologies to lower their compliance costs.

Alberta

On November 22, 2015, the Government of Alberta introduced its Climate Leadership Plan. Under this strategy, the *Climate Leadership Act* (the "**CLA**") came into force on January 1, 2017 and established a fuel charge that was compliant with federal requirements. On December 14, 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.

In June 2019, the Government of Alberta repealed the CLA and the federal fuel charge took effect in Alberta. In accordance with the GGPPA, the fuel charge payable in Alberta is currently $50/tonne of CO2e and will increase to $65/tonne on April 1, 2023. In December 2019, the federal government approved Alberta's Technology Innovation and Emissions Reduction ("**TIER**") regulation which applies to large emitters and those who have opted-in. The TIER regulation came into effect on January 1, 2020 and replaced the previous Carbon Competitiveness Incentives Regulations.

The provisions of the TIER regulation required that an interim review of the regulation be completed by December 31, 2022 giving stakeholders an opportunity to provide input on improvements to the TIER system and to enable the regime to meet the updated federal benchmark criteria for the assessment of the carbon pricing systems for 2023 to 2030. Following the comment period, the Technology Innovation and Emissions Amendment Regulation was adopted with certain amendments to the TIER Regulation becoming effective January 1, 2023. These amendments include meeting the federal standards for Alberta's carbon pricing system, the creation of sequestration credits for carbon capture, utilization and storage ("**CCUS**") technology projects and amendments to the number of credits that can be used to meet emission targets. The TIER regulation is set to undergo another review by December 31, 2026.

The TIER regulation applies to emitters that emit more than 100,000 tonnes of CO2e per year in 2016 or any subsequent year. The 2020 target for most TIER-regulated facilities is to reduce emissions intensity by 10% as measured against that facility's individual benchmark, with a further 1% reduction for each subsequent year. Under the amendments, a 2% annual tightening rate will apply to facility-specific and high performance benchmarks. The facility-specific benchmark does not apply to all facilities. Certain facilities, such as those in the electricity sector, are compared against the good-as-best-gas standard. Similarly, for facilities that have already made substantial headway in reducing their emissions, a different "high-performance" benchmark is available to ensure that the cost of ongoing compliance takes this into account. Under the TIER regulation, facilities in high-emitting sectors can opt-in to the program in specified circumstances despite the fact that they do not meet the 100,000 tonne threshold. The amendments reduced the threshold for those to opt-in from 10,000 tonnes of CO2e to 2,000 tonnes of CO2e per year. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports and facilities that are unable to achieve their targets may either purchase credits from other facilities, purchase carbon offsets or pay a levy to the Government of Alberta. The TIER regulation will continue to apply in Alberta for so long as it meets the federal stringency standards and the federal backstop will apply to the emission sources not covered by the TIER program.

The Government of Alberta aims to lower annual methane emissions by 45% by 2025. Pursuant to this goal, the Government of Alberta enacted the Methane Emission Reduction Regulation (the "**Alberta Methane Regulations**") on January 1, 2020, and the AER simultaneously released an updated edition of *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting* ("**Directive 060**"). The release of the updated Directive 060 complements a previously released update to *Directive 017: Measurement Requirements for Oil and Gas Operations* that took effect in December 2018. Together, these new directives represent Alberta's first step toward achieving its 2025 goal. In November 2020, the Government of Canada and the Government of Alberta reached an equivalency agreement with respect to the Alberta Methane Regulations and the Federal Methane Regulations in which an order was declared that the Federal Methane Regulations will cease to apply in Alberta as of January 1, 2023.

Alberta was also the first jurisdiction in North America to direct dedicated funding to implement CCUS across industrial sectors. Alberta has committed $1.24 billion through 2025 to fund two commercial-scale

CCUS projects that will begin commercializing the technology on the scale needed to be successful. Both projects will help reduce the CO_2 emissions from the oil sands and fertilizer sectors and reduce GHG emissions by 2.76 million megatonnes per year.

On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*, which deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

In May 2021, the Government of Alberta announced a competitive bid process under which it would issue rights for carbon sequestration, focusing on the development of strategically placed carbon sequestration hubs, avoiding stand-alone injection operations. As of the fall of 2022, the Government of Alberta approved a total of 25 hub proposals through two competitive bid processes. The selected companies will begin exploring how to safely develop their carbon storage hubs. If a proponent can successfully demonstrate their project can provide permanent storage, companies will have the opportunity to apply for the right to inject captured carbon dioxide at such project. The Government of Alberta has also announced it will invest $40 million in 11 CCUS hub projects through Emissions Reduction Alberta.
On November 5, 2021, the Government of Alberta released the Alberta Hydrogen Roadmap. Hydrogen is positioned to play a significant role in the de-carbonization of the global economy and Alberta has significant opportunity to play a major role both nationally and internationally. The Hydrogen Roadmap is divided into two phases. The first phase focuses on establishing policy, investing in technology to reduce the carbon intensity of hydrogen production and accelerating commercialization across the supply chain. The second phase will focus on growth and achieving scale through improved technologies and commercialization. The Alberta Utilities Commission also released its Hydrogen Inquiry Report in September 2022 which reviewed the viability and impacts of hydrogen blending into natural gas distribution systems in Alberta.

In May 2021, the Government of Alberta announced a competitive bid process under which it would issue rights for carbon sequestration, focusing on the development of strategically placed carbon sequestration hubs, avoiding stand-alone injection operations. As of the fall of 2022, the Government of Alberta approved a total of 25 hub proposals through two competitive bid processes. The selected companies will begin exploring how to safely develop their carbon storage hubs. If a proponent can successfully demonstrate their project can provide permanent storage, companies will have the opportunity to apply for the right to inject captured carbon dioxide at such project. The Government of Alberta has also announced it will invest $40 million in 11 CCUS hub projects through Emissions Reduction Alberta.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the **"MRGGA**") to regulate GHG emissions in the province. The MRGGA, partially proclaimed into force on January 1, 2018, establishes a framework to reduce GHG emissions by 20% of 2006 levels by 2020. On October 18, 2016, the Government of Saskatchewan released a White Paper on Climate Change, resisting a carbon tax and committing to an approach that focuses on technological innovation and adaptation. The Government of Saskatchewan subsequently released Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy (the "**Saskatchewan Strategy**") outlining its strategy to reduce GHG emissions by 12 million tonnes by 2030.

The MRGGA, which is partially compliant with the federal emissions trading system and was partially proclaimed into force on January 1, 2018, establishes a framework to reduce GHG emissions by 20% of 2006 levels by 2020. An amended version of the MRGGA was proclaimed in full on December 18, 2018, establishing the framework of an output-based emissions management framework. In November 2022, the province of Saskatchewan received confirmation that a provincial plan has been approved to replace the federally imposed carbon tax on industrial emitters effective as of January 1, 2023. The Saskatchewan OBPS meets the federal stringency requirements and regulated emitters will receive credit for every tonne of CO2e under their permitted amount. The OBPS program in Saskatchewan will also include credits for

CCUS. The OBPS in Saskatchewan is implemented pursuant to the Saskatchewan Strategy. As noted above, the federal fuel charge applies in Saskatchewan.

Under the MRGGA, facilities that have annual GHG emissions in excess of 50,000 tonnes are regulated to meet the province's reduction targets. The following regulations were enacted throughout 2018: The Management and Reduction of Greenhouse Gases (General and Electricity Producer) Regulations, the Management and Reduction of Greenhouse Gases (Reporting and General) Regulations and The Management and Reduction of Greenhouse Gases (Standards and Compliance) Regulations. These regulations establish reporting requirements and impose various emissions limits for those emitters that fall within the program. On January 1, 2019, The Oil and Gas Emissions Management Regulations (the Saskatchewan O&G Emissions Regulations) came into effect. The Saskatchewan O&G Emissions Regulations apply to licensees of oil facilities that may generate more than 50,000 tonnes of CO2e per year, obliging each licensee to propose an emissions reduction plan in accordance with an annual emissions limit with the goal of achieving annual emissions reductions of 40% to 45% by 2025. The Saskatchewan O&G Emissions Regulations aim to reduce 4.5 million tonnes of CO2e emissions by 2025, with a total reduction of 38.2 million tonnes CO2e between 2020 and 2030.

On April 10, 2019, Saskatchewan produced the first annual report on climate resilience. The report measures the province's progress on goals set out under Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy. Among these goals is the aim of increasing the role of renewable energy in the provincial energy mix to 50% by 2030.

In October 2019, *The Oil and Gas Conservation Amendment Act* was proclaimed into force. This Act, in part, amends the SKOGCA to the extent necessary to bring it into alignment with the Saskatchewan O&G Emissions Regulations discussed above.

To facilitate its emissions reduction efforts, the Government of Saskatchewan has implemented *Directive PNG017: Measurement Requirements for Oil and Gas Operations*, which came into force in December 2019 and was amended in April 2020, and *Directive PNG036: Venting and Flaring Requirements*, which came into force in April 2020. Together with the Saskatchewan O&G Emissions Regulations, these directives enable the Government of Saskatchewan to regulate emissions reductions within the province. In November 2020, the Government of Canada and the Government of Saskatchewan announced that they had finalized an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply. The equivalency agreement terminates on or by December 31, 2024. In furtherance of these goals and agreements, in March 2021, the Government of Saskatchewan announced it would provide $500,000 to support innovative research and technology for measuring and monitoring gas volumes and emissions, which will be overseen by the Saskatchewan Research Council.

In January 2021, the Government of Saskatchewan announced support for three projects expected to reduce methane emissions, including a new flare-gas-to-power project, an expansion of gas processing facilities and a new gas fractionation plant. The Saskatchewan Petroleum Innovation Incentive ("**SPII**") and Oil and Gas Processing Investment Incentive ("**OGPII**") give this support. The SPII and OGPII provide a percentage of transferable royalty credits after private funding has been obtained and the facilities have been built.

In September 2021, Saskatchewan's Energy and Resource Minister announced that one of the government's key priorities would be increasing investment in Carbon Capture, Utilization and Storage ("**CCUS**") through enhanced oil recovery CCUS projects.

Indigenous Rights

Constitutionally mandated government-led consultation with and, if applicable, accommodation 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 *United Nations Declaration of the Rights of*

Indigenous Peoples ("**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 December 2020, the federal government introduced *Bill C-15: An Act respecting the United Nations Declaration on the Rights of Indigenous Peoples Act* ("**Bill C-15**"). Similar to British Columbia's DRIPA, the intention of Bill C-15 is to establish a process whereby the Government of Canada will 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. Bill C-15 received royal assent and was passed into law on June 21, 2021.

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 Bill C-15 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.

Accountability and Transparency

In 2015, the federal government's *Extractive Sector Transparency Measures Act* ("**ESTMA**") came into effect, which imposed mandatory reporting requirements on certain entities engaged in the "commercial development of oil, gas or minerals", including exploration, extraction and holding permits. All companies subject to ESTMA must report payments over CAD$100,000 made to any level of a Canadian or foreign government (including Indigenous groups), including royalty payments, taxes (other than consumption taxes and personal taxes), fees, production entitlements, bonuses, dividends (other than ordinary dividends paid to shareholders), infrastructure improvement payments and other prescribed categories of payments.

RISK FACTORS

There are a number of inherent risks associated with the exploration and production of oil and gas reserves. Many of these risks are beyond the control of the Corporation. Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings available under the Corporation's SEDAR profile at www.sedar.com before making an investment decision.

The risks described below are not the only risks facing the Corporation. Additional risks not presently known to Lycos or that Lycos currently deems immaterial may also impair Lycos's business operations. If any of the following risks actually occur, Lycos's business, financial condition and financial performance could be materially and adversely affected.

Nature of the Business

An investment in Lycos should be considered highly speculative due to the nature of Lycos's involvement in the exploration for, and the acquisition, production and marketing of, oil and natural gas reserves and its current stage of development. Oil and gas operations involve many risks which even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by Lycos.

Commodity Price Volatility

Lycos's financial performance and financial condition are dependent on the prevailing prices of Crude Oil and natural gas. Crude Oil and natural gas prices have fluctuated widely in the recent past and are subject to fluctuations in response to relatively minor changes in supply, demand, market uncertainty and other factors that are beyond the Corporation's control.

Crude Oil and natural gas prices are impacted by a number of factors including, but not limited to: the global supply of and demand for Crude Oil and natural gas; global economic conditions; the actions of OPEC and OPEC+; government regulation; political stability; the ability to transport crude to markets; developments related to the market for liquefied natural gas; the availability and prices of alternate fuel sources; and weather conditions. Concerns over global economic conditions, fluctuations in interest rates and foreign exchange rates, stock market volatility, energy costs, geopolitical issues, Russia's military invasion of Ukraine, OPEC+ actions, inflation, the availability and cost of credit, the deceleration of economic growth in the People's Republic of China, trade disputes between the United States and the People's Republic of China, civil unrest in Venezuela and Iran and the outbreak of COVID-19 have contributed to increased economic uncertainty and diminished expectations for the global economy. In addition, significant growth in crude production volumes has resulted in pressure on transportation and pipeline capacity, resulting in fluctuations in the price of oil and natural gas. All of these factors are beyond the Corporation's control and can result in a high degree of price volatility.

Fluctuations in the price of commodities may impact the value of Lycos's assets and the ability to maintain its business and to fund growth projects. Prolonged periods of commodity price depression and volatility may also negatively impact Lycos's ability to meet guidance targets and meet all of its financial obligations as they come due. Any substantial and extended decline in the price of oil and gas would have an adverse effect on Lycos's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on Lycos's business, financial condition, results of operations, prospects and the level of expenditures for the development of oil and natural gas reserves, including delay or cancellation of existing or future drilling or development programs or curtailment in production.

Any material or sustained decline in prices could result in a reduction of Lycos's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or gas and a reduction in the volumes of Lycos's reserves. Lycos might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in Lycos's expected net production revenue and a reduction in its oil and gas acquisition, development and exploration activities.

Crude Oil and natural gas prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies and OPEC+ actions. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

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

Lycos will conduct regular assessments of the carrying value of its assets. If Crude Oil and natural gas prices decline significantly and remain at low levels for an extended period of time, the carrying value of Lycos's assets may be subject to impairment.

Public Health Crises

The COVID-19 pandemic has negatively impacted the Canadian, US, and global economies; disrupted Canadian, US, and global supply chains; disrupted financial markets; contributed to a decrease in interest rates; resulted in ratings downgrades, credit deterioration and defaults in many industries; forced the closure of many businesses, led to loss of revenues, increased unemployment and bankruptcies; and necessitated the imposition of quarantines, physical distancing, business closures, travel restrictions, and sheltering-in-place requirements in Canada, the US, and other countries. If the pandemic is prolonged, including through subsequent waves, or if additional variants of COVID-19 emerge which are more transmissible or cause more severe disease, or if other diseases emerge with similar effects, the adverse impact on the economy could worsen. It remains uncertain how the macroeconomic environment, and societal and business norms will be impacted following this COVID-19 pandemic.

The COVID-19 pandemic has also created additional operational risks for the Corporation, including the need to provide enhanced safety measures for employees and customers; comply with rapidly changing regulatory guidance; address the risk of, attempted fraudulent activity and cybersecurity threat behaviour. Lycos is also exposed to human capital risks due to issues related to health and safety matters, and other environmental stressors as a result of measures implemented in response to the COVID-19 pandemic, as well as the potential for a significant proportion of Lycos's employees, including key executives, to be unable to work effectively, because of illness, quarantines, sheltering-in-place arrangements, government actions or other restrictions in connection with the pandemic.

The extent to which the COVID-19 pandemic continues to impact the Corporation's results, business, financial condition or liquidity will depend on future developments in Canada, the US and globally, including the development and widespread availability of efficient and accurate testing options, and effective treatment options or vaccines. Despite the approval of certain vaccines by the regulatory bodies in Canada and the US, the ongoing evolution of the development and distribution of an effective vaccine also continues to raise uncertainty.

Borrowings

The level of Lycos's indebtedness from time to time could impair its ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise, especially if its above industry standards. The Corporation's ability to meet its debt service obligations will depend on its future operations which will be subject to prevailing industry conditions and other factors, many of which are beyond the control of Lycos. In addition, the Corporation will be required to comply with the financial and other covenants included in its borrowing facilities.

As certain of the indebtedness may bear interest at rates which fluctuate with prevailing interest rates, increases in such rates would increase its interest payment obligations and could have a material adverse effect on its financial condition and results of operations. Further, the Corporation's indebtedness is secured by substantially all of its assets. In the event of a violation by the Corporation of any covenants under its credit facility or any other default on its obligations relating to its indebtedness, the lender could declare such indebtedness to be immediately due and payable, and in certain cases, foreclose on Lycos's assets.

Availability of Capital

As a result of recent economic uncertainties in the oil and gas industry and, in particular, the lack of risk capital available to the junior resource sector, Lycos, along with other junior resource entities, may have reduced access to bank debt and to equity. Lycos anticipates that it will make substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. The Corporation intends that these capital expenditures will be financed out of funds generated from operations, bank borrowings, if available, and possible issuances of debt or equity securities, Lycos's ability to fund future capital expenditures is dependent on, among other factors, the overall state of lending and capital markets and investor and lender appetite for investments in the energy industry, generally, and Lycos's securities in particular. In particular, the recent global outbreak of COVID-19 has adversely effected lending and capital markets. See "*Public Health Crises*", above.

To the extent that external sources of capital become limited, unavailable or available only on onerous terms, Lycos's ability to invest and to maintain existing assets and to undertake or complete future drilling programs may be impaired, and its assets, liabilities, business, financial condition and results of operations may be materially and adversely affected as a result.

There can be no assurance that debt or equity financing, or cash flow from 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 Lycos. Moreover, future activities may require Lycos to alter its capitalization significantly. To the extent that external sources of capital become limited, unavailable or available only on onerous terms, Lycos's ability to invest and to maintain existing assets and to undertake or complete future drilling programs may be impaired, and its assets, liabilities, business, financial condition and results of operations may be materially and adversely affected as a result.

Compliance with Licenses, Contracts and Other Obligations

The Corporation's assets are held in the form of licences and leases and working interests in licences and leases. The Corporation's operations must be carried out in accordance with the terms of these licences, operating agreements, annual work programs and budgets together with any conditions incumbent on the Corporation at the time the relevant asset was acquired such as ongoing royalty and other rental payments. If the Corporation or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire.

In addition, the operations of the Corporation require licences and permits from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all necessary licences and permits that are required to carry out exploration and development at its properties. The permitting process can take significant time, meaning that exploration and development projects have a longer cycle time to completion than they might elsewhere.

Relevant legislation provides that fines may be imposed and a licence may be suspended or terminated if a licence holder, or party to a related agreement, fails to comply with its obligations under such licence or agreement, or fails to make timely payments of levies and taxes for the licensed activity, provide the required geological information or meet other reporting requirements.

It may from time to time be difficult to ascertain whether the Corporation has complied with obligations under licences as the extent of such obligations may be unclear or ambiguous and regulatory authorities in jurisdictions in which the Corporation does business, or in which it may do business in the future, may not be forthcoming with confirmatory statements that work obligations have been fulfilled, which can lead to further operational uncertainty.

In addition, the Corporation and its commercial partners, as applicable, have obligations to operate assets in accordance with specific requirements under their licences and related agreements, field development agreements, laws and regulations. If the Corporation or its partners were to fail to satisfy such obligations with respect to a specific field, the licence or related agreements for that field may be suspended, revoked or terminated.

Regulations and policies relating to licences and permits may change, be implemented in a way that the Corporation does not currently anticipate or take significantly greater time to obtain. These licences and permits are subject to numerous requirements, including compliance with the environmental regulations of the local governments.

The suspension, revocation, withdrawal or termination of any of the licences or related agreements pursuant to which the Corporation may conduct business, as well as any delays in the continuous development of or production at the Corporation's fields caused by the issues detailed above could materially and adversely affect the business, results of operations, financial condition or prospects. In addition, failure to comply with the obligations under the licences or agreements pursuant to which the Corporation conducts business, whether inadvertent or otherwise, may lead to fines, penalties, restrictions, withdrawal of licences and termination of related agreements.

Exploration Risks

Oil and natural gas exploration involves a high degree of risk and there is no assurance that expenditures made on exploration by Lycos will result in new discoveries of oil or natural gas in commercial quantities. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over pressured zones and tools lost in the hole, and changes in drilling plans and locations as a result of prior Exploratory Wells or additional seismic data and interpretations thereof.

The long term commercial success of Lycos depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. No assurance can be given that Lycos will be able to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, Lycos may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic.

Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs.

Production Risks

The Corporation's gas and oil production operations are subject to numerous risks common to its industry, including, but not limited to, premature decline of reservoirs, incorrect production estimates, invasion of water into producing formations, geological uncertainties such as unusual or unexpected rock formations and abnormal geological pressures, low permeability of reservoirs, contamination of gas and oil, blowouts, oil and other chemical spills, explosions, fires, equipment damage or failure, natural disasters, uncontrollable flows of oil, gas or well fluids, adverse weather conditions, shortages of skilled labour, delays in obtaining regulatory approvals or consents, pollution and other environmental risks.

In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While close well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Any of these events could lead to environmental damage, injury to persons or property and other species, failure to produce gas, natural gas liquids and oil in commercial quantities or an inability fully to produce reserves, all of which could cause substantial damage to Lycos or its reputation and put at risk some or all its interests in licences, which enable the Corporation to produce, and could result in incurrence of fines or penalties, criminal sanctions potentially being enforced against the Corporation and its management, as well as other governmental and third-party claims. Consequent production delays and declines in field operating conditions and other adverse actions taken by third parties may result in the Corporation's revenue and cash flow levels being adversely affected.

Should any of these risks materialise, the Corporation could incur legal defence costs, remedial costs and substantial losses, including those due to injury or loss of life, human health risks, severe damage to or destruction of property, natural resources and equipment, environmental damage, unplanned production outages, clean-up responsibilities, regulatory investigations and penalties, increased public interest in the Corporation's operational performance and suspension of operations

Fiscal, Royalty Regimes and Exchange Rates

In addition to federal regulation, most U.S. states have legislation and regulations which govern land tenure, drilling and construction permits, royalties, production rates, environmental protection and other matters. The applicable royalty regime is a significant factor in the profitability of oil and natural gas production.

As of the date hereof, there are no significant restrictions on the repatriation of capital and distribution of earnings that will affect Lycos's U.S. operations. There can be no assurance, however, that restrictions on repatriation of capital or distributions of earnings will not affect Lycos in the future. Amendments to domestic or foreign taxation laws and regulations in the countries in which Lycos will have assets or operations which alter tax rates and/or capital allowances could have a material adverse impact on Lycos.

Lycos is subject to the risk that currencies will not be convertible at satisfactory rates, that fluctuations in the conversion rates between Canadian and U.S. currencies may result in higher general and administrative expenses or may not accurately reflect the relative value of goods and services available or required. An increase in interest rates could result in a significant increase in the amount Lycos pays to service debt. Variations in foreign exchange rates and interest rates could have a material adverse impact on the business and operations of the Corporation.

Funds raised through equity issuances are generally raised in Canadian dollars whereas the majority of Lycos's expenditures will be typically incurred in other currencies and therefore currency fluctuations could have a material impact on Lycos's results of operations. The exchange rates between the Canadian and U.S. currencies have varied substantially recently. Lycos does not currently anticipate using exchange rate derivatives to manage exchange rate risks.

Trade Relations

World-wide political and economic risks seem to be intensifying and there are added risks and uncertainties around the impact of new policies proposed by the U.S. government, including, but not limited to, the renegotiation of international trade agreements; the potential changes to U.S. trade policies; and tax reform. Major developments in these areas could have a material adverse effect on Lycos.

The North American Free Trade Agreement ("**NAFTA**") has been renegotiated and on November 30, 2018, Canada, the U.S. and Mexico signed the Canada-United States-Mexico Agreement ("**USMCA**") which has replaced NAFTA. The USMCA was ratified by Mexico's Senate in June 2019, by the United States' Senate in January 2020 and by the Canadian Parliament in March 2020. The former U.S. administration also took action with respect to reduction of regulation which affected relative competitiveness of other jurisdictions. The Biden administration in the US put a hold on issuance or approval of new oil and natural gas leases and drilling permits on U.S. federal lands and has indicated that it will roll-back certain policies of the former administration. While it is unclear which legislation or policies of the former administration will be rolled-back and if such roll-backs will be a priority of the new administration in light of the ongoing COVID-19 pandemic, any future actions taken by the new U.S. administration could have a negative impact on the United States economy and on the businesses, financial conditions, results of operations and the valuation of oil and natural gas companies operating in the United States, including the Corporation.

Operational Health and Safety and Environmental Regulations and Requirements

The Corporation operates in an industry that has certain hazardous risks and consequently is subject to comprehensive laws and regulations, especially with regard to the protection of health, safety and the environment. The terms of licences, permits, regulatory orders, or permissions may include more stringent operational, environmental or health and safety requirements. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities.

In early 2021, the Biden administration recommitted the United States to the Paris Climate Agreement and targeted a reduction of 50-52% greenhouse gas emissions by the year 2030. In order to achieve such goal, in 2021, the Biden administration introduced initiatives, which include policies to address climate change, energy efficiency, and clean energy. If the Biden administration and the United States Congress adopt stricter standards for, and increase oversight and regulation over, the exploration and production industry at the federal level, these measures could lead to increased costs or additional operating restrictions. Also, there is the potential for climate change legislation which could affect demand for oil on a long-term basis.

Any failure by the Corporation or one of its sub-contractors, whether inadvertent or otherwise, to comply with applicable legal or regulatory requirements or the terms of licenses or permits may give rise to civil, administrative or criminal liabilities, civil fines and penalties, delays or restrictions in acquiring or disposing of assets or delays in securing or maintaining the required permits, licences and approvals. A lack of regulatory compliance may even lead to denial or termination of licences the Corporation requires for operating its sites or could result in other operational restrictions or obligations.

Further, any environmental damage, loss of life, injury or damage to property caused by the Corporation's operations could damage its reputation in the areas in which it operates. Negative sentiment towards the Corporation could result in a lack of willingness of municipal authorities to grant the necessary licences or permits for Lycos to operate its business and in opposition to the Corporation's further operations in the area. If the Corporation develops a reputation of having an unsafe work site it may also impact Lycos's ability to attract and retain the necessary skilled employees and consultants to operate its business.

The Corporation's operations have the potential to impact soil, air and water quality, biodiversity and ecosystems. Obtaining development or production licences and permits may become more difficult or may be delayed due to governmental, regional or local environmental consultation, scientific studies, approvals or other considerations or requirements. Furthermore, third-parties such as environmental organizations may judicially contest licences and permits already granted by relevant authorities and operations may be subject to other administrative or judicial challenges.

New laws and regulations, new national executive orders, the imposition of more stringent requirements in licences, increasingly strict enforcement of, or new interpretations of, existing laws, regulations and licences, or the discovery of previously unknown contamination or hazards may require further high cost expenditures in order for the Corporation to achieve compliance or may result in a material increase in the cost of production or development activities or even a curtailment of production

Insurance

Lycos's involvement in the exploration for and development of oil and gas properties may result in Lycos becoming subject to liability for pollution, blow outs, property damage, personal injury or other hazards. Although Lycos will obtain 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, Lycos may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or for other reasons. The payment of such uninsured liabilities would reduce the funds available to Lycos. The occurrence of a significant event that Lycos is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on Lycos's financial position, results of operations or prospects.

Project Risks

Lycos is expected to manage and participate in a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Project cost estimates may not be accurate due to a lack of history of comparable projects. Furthermore, significant project cost over runs could make a project uneconomic.

Lycos's ability to execute projects and market oil and natural gas will depend upon numerous factors beyond Lycos's control, including: the availability of processing capacity; the availability and proximity of pipeline capacity; the availability of storage capacity; the supply of and demand for oil and natural gas; the availability of alternative fuel sources; the effects of inclement weather; the availability of drilling and related equipment; unexpected cost increases; accidental events; currency fluctuations; changes in regulations; the availability and productivity of skilled labour; and the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

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

Inflation and Cost Management

Lycos's operating costs could escalate and become uncompetitive due to supply chain disruptions, inflationary cost pressures, equipment limitations, escalating supply costs, commodity prices, and additional government intervention through stimulus spending or additional regulations. The Corporation's inability to manage costs may impact project returns and future development decisions, which could have a material adverse effect on its financial performance and funds from operations.

The cost or availability of oil and gas field equipment may adversely affect the Corporation's ability to undertake exploration, development and construction projects. The oil and gas industry is cyclical in nature and is prone to shortages of supply of equipment and services including drilling rigs, geological and geophysical services, engineering and construction services, major equipment items for infrastructure projects and construction materials generally. These materials and services may not be available when required at reasonable prices. A failure to secure the services and equipment necessary to Lycos's operations for the expected price, on the expected timeline, or at all, may have an adverse effect on the Corporation's financial performance and funds from operations.

Competition

Lycos actively competes for acquisitions, exploration leases, licences and concessions and skilled industry personnel with a substantial number of other oil and gas companies, many of which have significantly greater financial resources than Lycos. Lycos's competitors include major integrated oil and natural gas companies and numerous other independent oil and natural gas companies and individual producers and operators.

The oil and gas industry is highly competitive. Lycos's competitors for the acquisition, exploration, production and development of oil and natural gas properties, and for capital to finance such activities include companies that have greater financial and personnel resources available to them than Lycos.

Lycos's ability to successfully bid on and acquire additional property rights, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with customers will be dependent upon developing and maintaining close working relationships with its future industry partners and joint operators and its ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment.

Cost of New Technologies

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

Title to Assets

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

Vendors of oil and gas interests have not in the past and may not in the future warrant title to assets acquired by Lycos in the United States. The nature of the oil and gas leasing and title regime in the U.S. basins in which Lycos will hold an interest is such that interests in large tracts of acreage may be represented by hundreds or thousands of leases and obtaining absolute confirmation of chain of title would be time consuming and expensive. Lycos will conduct such title reviews in connection with its principal properties as it believes are commensurate with the value of such properties and will conduct an extensive title review of a particular area prior to commencement of drilling. However, there can be no assurance of title. Title may be subject to unregistered liens and other defects which, if affecting a core area, could have a material adverse effect on Lycos, its financial condition, results of operations and prospects.

Condition of Assets

The Corporation seeks to optimise or refurbish producing assets where possible to maximise the efficiency of its operations while avoiding significant expenses associated with purchasing new equipment. The Corporation's assets require ongoing maintenance to ensure continued operational integrity. There can be no guarantee that the Corporation's assets or the assets used by the Corporation will continue to operate without fault and not suffer material damage through, for example, wear and tear, severe weather conditions, natural disasters or industrial accidents. If the Corporation's assets or the assets used by the Corporation do not operate at or above expected efficiencies, the Corporation may be required to invest substantial expenditure beyond the amounts budgeted. Any material damage to these assets or significant capital expenditure on these assets for improvement or maintenance may have a material adverse effect on the Corporation's business, results of operations, financial condition or prospects. In addition, as with planned operating and capital expenditure, there is no guarantee that the amounts expended will ensure continued operation without fault or address the effects of wear and tear, severe weather conditions, natural disasters or industrial accidents.

Reserve and Resource Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids resources, reserves and cash flows to be derived therefrom, including many factors beyond Lycos's control. In estimating reserves, the chance of commerciality is effectively 100%. For prospective resources, the chance of commerciality will be the product of the chance that a project will result in a discovery of petroleum or natural gas and the chance that an accumulation will be commercially developed. There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

The reserve and associated cash flow information and estimates represent estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom prepared by different engineers, or by the same engineers at different times, may vary. Lycos's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material. Further, the 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 to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluation.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

Actual production and revenues derived from the Corporation's assets will vary from the estimates, potentially materially, including as a result of 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.

There are numerous uncertainties inherent in estimating quantities of resources, including many factors beyond Lycos's control, and no assurance can be given that the indicated level of resources will be realized. In general, estimates of recoverable resources are based upon a number of factors and assumptions made as of the date on which the resource estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the assumed effects of regulation by governmental agencies and estimates of future commodity prices and operating costs, all of which may vary considerably from actual results. All such estimates are, to some degree, uncertain and classifications of resources are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable natural gas and the classification of such resources based on risk of recovery prepared by different engineers or by the same engineers at different times may vary substantially.

Geological risking of prospective resources addresses the probability of success for the discovery of petroleum; this risk analysis is conducted independently of probabilistic estimates of petroleum volumes and without regard to the chance of development. Principal risk elements of the petroleum system include: (i) trap and seal characteristics; (ii) reservoir presence and quality; (iii) source rock capacity, quality and maturity; and (iv) timing, migration and preservation of petroleum in relation to trap and seal formation. Geological risk assessment is a highly subjective process dependent upon the experience and judgment of the evaluators.

Estimates with respect to resources that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of resources, rather than upon actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same resources based upon production history will result in variations, which may be material, in the estimated resources.

Resources estimates may require revision based on actual production experience. Market price fluctuations of natural gas prices may render uneconomic the recovery of the resources.

Abandoned Royalties

The Corporation has significant liability in respect of abandoned royalties in respect of its oil and gas leases in accordance with the laws of the State of Mississippi. Although the Corporation has taken legal advice from Mississippi counsel to support its treatment of the abandoned royalties, there can be no guarantee that such abandoned royalties will not be claimed or become payable to the State of Mississippi earlier than project by Lycos. If that were to occur in respect of a material portion of the abandoned royalties currently on the Corporation's balance sheet, Lycos's financial condition and working capital could be materially adversely affected.

Abandonment

The Corporation may become responsible for costs associated with abandoning and reclaiming wells, facilities and pipelines which it uses for the processing of gas and oil reserves. Such Abandonment costs will be incurred by the Corporation at the end of the operating life of some of Lycos's properties. The ultimate Abandonment costs are uncertain and cost estimates can vary in response to many factors including changes to relevant legal requirements, the emergence of new restoration techniques, any shortage of plugging contractors, difficult terrain or weather conditions or experience at other production sites. The expected timing and amount of expenditure can also change, for example, in response to changes in reserves, wells losing commercial viability sooner than forecasted or changes in laws and regulations or their interpretation.

As a result, there could be significant adjustments to provisions for Abandonment established by the Corporation which would affect future financial results. The use of other funds to satisfy such Abandonment costs may impair the Corporation 's ability to focus capital investment in other areas of its business, which could materially and adversely affect the Corporation's business, results of operations, financial condition or prospects.

Climate Change Legislation

Lycos's exploration and production facilities and other operations and activities will emit greenhouse gases and Lycos may be required to comply with greenhouse gas emissions legislation at the state or federal level. Continued public concern regarding climate change, the extent to which it is caused by human activity and potential mitigation through regulation could have a material impact on Lycos's business, international agreements, national and regional legislation, and regulatory measures to limit greenhouse ("**GHG**") emissions are currently in place or in various stages of discussion or implementation. Given that certain of the Corporation's operations are associated with emissions of GHGs, these and other GHG emissions-related laws, policies and regulations may result in substantial capital, compliance, operating and maintenance costs. The level of expenditure required to Corporation with these laws and regulations is uncertain and expected to vary depending on the laws enacted by particular countries.

The emission reduction targets and other provisions of legislative or regulatory initiatives and policies enacted in the future by the United States or states in which the Corporation operates, could adversely impact Lycos's business by imposing increased costs in the form of higher taxes or rises in the prices of emission allowances, limiting the Corporation's ability to develop new gas and oil reserves, transport hydrocarbons through pipelines or other methods to market, decreasing the value of Lycos's assets, or reducing the demand for hydrocarbons and refined petroleum products.

In addition, the Corporation may be subject to activism from groups campaigning against fossil fuel extraction, which could affect Lycos's reputation, disrupt its campaigns or programs, require the Corporation to incur significant, unplanned expense to respond or react to intentionally disruptive campaigns, result in limitations or restrictions on certain sources of funding (including investment from current or other potential investors as well as funding from commercial banks), create blockades to interfere with operations or otherwise negatively impact the Corporation's business or prospects.

Reserve Replacement

Lycos's future oil and natural gas reserves, production, and cash flows to be derived therefrom will be dependent on Lycos successfully acquiring or discovering new reserves. Without the continual addition of new reserves, any existing reserves Lycos may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Lycos's reserves will depend not only on Lycos's ability to develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. There can be no assurance that Lycos's future exploration and development efforts will result in the discovery and development of additional commercial accumulations of oil and natural gas.

Anticipated Benefits of Acquisitions and Dispositions

Lycos is expected to make acquisitions and dispositions of businesses and assets. Achieving the benefits of these acquisitions will depend in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner, as well as realizing the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of Lycos. The integration of acquired businesses may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters.

Management of Lycos will assess the value and contribution of individual properties and other assets. In this regard, non-core assets are expected to be periodically disposed of, so that Lycos can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of Lycos, if disposed of, could realize less than their carrying amount on the financial statements of Lycos.

Reliance on Third Parties

The Corporation's ability to market its Crude Oil and natural gas can depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. Various production, marketing and transportation conditions may cause delays in gas, natural gas liquids and oil production and adversely affect the Corporation's business. The Corporation relies on gas and oil field suppliers and contractors to provide materials and services that facilitate its production activities, including plugging and Abandonment contractors. Any competitive pressures on the oil field suppliers and contractors could result in a material increase of costs for the materials and services required to conduct the Corporation's business.

Where other companies operate assets in which the Corporation has an interest, Lycos will have limited ability to exercise influence over the operation of those assets or their associated costs. Therefore, the Corporation's return on assets operated by others may therefore depend upon a number of factors that may be outside its control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

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

The Corporation and its off-takers rely upon the availability of pipeline and storage capacity systems, including such infrastructure systems that are owned and operated by third parties. As a result, the Corporation may be unable to access the infrastructure and systems which it currently uses or plans to use, or source alternatives or otherwise be subject to interruptions or delays in the availability of infrastructure and systems necessary for the delivery of its gas, natural gas liquids and oil to commercial markets. In addition, such infrastructure may be close to its design life and decisions may be taken to decommission such infrastructure or perform life extension work to maintain continued operations. Any of these events could result in disruptions to the Corporation's projects thereby impacting its ability to deliver gas, natural gas liquids and oil to commercial markets or may increasing the Corporation's costs associated with the production of gas, natural gas liquids and oil reliant upon such infrastructure/systems.

Further, the Corporation's off-takers could become subject to increased tariffs imposed by government regulators or the third-party operators or owners of the transportation systems available for the transport of the Corporation's gas, natural gas liquids and oil, which could result in decreased off-taker demand and downward pricing pressure.

If the Corporation is unable to access infrastructure systems facilitating the delivery of its gas, natural gas liquids and oil to commercial markets due to its contractors or primary off-takes being unable to access the necessary equipment or transportation systems, the Corporation's operations will be adversely affected. If the Corporation is unable to source the most efficient and expedient infrastructure systems for its assets then delivery of its gas, natural gas liquids and oil to the commercial markets may be negatively impacted, as may its costs associated with the production of gas, natural gas liquids and oil reliant upon such infrastructure and systems.

Reliance on Key Personnel

Lycos's success will depend in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on Lycos's business, financial condition, results of operations and prospects. Lycos may not have any key person insurance in effect. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that Lycos will be able to attract and retain all personnel necessary for the development and operation of its business.

Management of Growth

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

Hedging

From time to time, Lycos may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, Lycos will not benefit from such increases.

Litigation

From time to time, the Corporation may be subject, directly or indirectly, to litigation arising out of its operations and the regulatory environments in its areas of operations. Categories of litigation that the Corporation may face include actions by royalty owners over payment disputes, personal injury claims and property related claims, including claims over property damage, trespass or nuisance.

Although the Corporation currently faces no material litigation, damages claimed under such litigation in the future may be material or may be indeterminate. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to Lycos and as a result, could have a material adverse effect on Lycos's assets, liabilities, business, financial condition and results of operations. In addition, the Corporation may be required to incur significant expenses or devote significant resources to defending against litigation. Adverse publicity surrounding litigation could also have a material effect on the Corporation's business.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of the United States. Lycos is not aware that any claims have been made in respect of its assets; however, if a claim arose in respect of such assets, or any of Lycos's future properties or assets, and was successful, such claim may have a material adverse effect on Lycos's business, financial condition, results of operations and prospects.

Breach of Confidentiality

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

Conflicts of Interest

Directors and officers of Lycos may also be directors and officers of other oil and gas companies involved in oil and gas exploration and development, and conflicts of interest may arise between their duties as officers and directors of Lycos and as officers and directors of such other companies. Such conflicts must be disclosed in accordance with and are subject to such other procedures and remedies as apply under the ABCA.

Active Trading Market

The liquidity of the Common Shares on the TSXV and the AIM will be influenced by a large number of factors, some specific to the Corporation and its operations and others outside its control and unrelated to the Corporation's operating performance, such as the operating and share price performance of other companies that investors may consider comparable to the Corporation, speculation about the Corporation in the press or the investment community, strategic actions by competitors, changes in market conditions and regulatory changes in any number of countries. There can be no guarantee that an active trading market for the Common Shares will be maintained.

Dilution of holders of Common Shares

Lycos may seek to raise financing to fund future acquisitions or other growth opportunities. The Corporation may, for these and other purposes, issue additional equity or convertible equity securities. As a result, existing holders of Common Shares may suffer dilution in their percentage ownership or the market price of the Common Shares may be adversely affected.

The Corporation has issued options under its stock option plan and has issued the Warrants and the Debentures. The Corporation may, in the future, issue further options, warrants or convertible debentures. The exercise or conversion of any such options, warrants or convertible debentures would result in dilution of the holdings of other Shareholders.

In addition, the Corporation may decide to offer additional Common Shares in the future. Subject to any applicable pre-emption right, any future issues of Common Shares by the Corporation may have a dilutive effect on the holdings of Shareholders and could have a material adverse effect on the market price of the Common Shares as a whole.

Investment Risk

An investment in a quoted Corporation is highly speculative, involves a considerable degree of risk, and is suitable only for persons or entities which have substantial financial means and who can afford to hold their ownership interests for an indefinite amount of time or to lose their investment principal. Potential investors should also consider the risks that are relevant to the industry in which the Corporation operates.

Seasonality and Weather Conditions

The level of activity in the oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Lycos's operations may be subjected to adverse weather conditions such as hurricanes, flooding and tropical storms in and around the Gulf of Mexico that can damage oil and natural gas facilities and delivery systems and disrupt operations, which can also increase costs and have a negative effect on Lycos's results of operations.

There can be no assurance that these seasonal factors will not adversely affect the timing and scope of Lycos's exploration and development activities, which could in turn have a material adverse impact on Lycos's business, operations and prospects.

IT and Cyber-Security

The Corporation depends on digital technology, among other things, to process and record financial and operating data, communicate with its employees and business partners, analyze seismic and drilling information, and estimate quantities of oil and gas resources and reserves. Accordingly, the Corporation is susceptible to cyber incidents (both deliberate and unintentional).

The unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information could disrupt the Corporation's business plans and negatively impact its operations in a number of ways. As cyber threats continue to evolve, the Corporation may be required to expend significant additional resources to continue to modify or enhance its protective measures or to investigate and remediate any information security vulnerabilities.

Third Party Credit Risk

Lycos may be exposed to third party credit risk through its contractual arrangements with future joint venture partners, marketers of its petroleum and natural gas production, counterparts to its financial instruments, including hedging activities, and other parties. In the event that any such entity fails to meet its contractual obligations to Lycos, such failures could have a material adverse effect on Lycos and its cash flow from operations..

Alternatives to and Changing Demand for Petroleum Products

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

Changing Investor Sentiment

A number of factors, including the concerns of the effects of the use of fossil fuels on climate change, concerns of the impact of oil and gas operations on the environment, concerns of environmental damage relating to spills of petroleum products during transportation and concerns of indigenous rights, have affected certain investors' sentiments towards investing in the oil and gas industry. As a result of these concerns, some institutional, retail and public investors have announced that they no longer are willing to fund or invest in oil and 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 the Corporation, its management and employees. Failing to implement the policies and practices as requested by institutional investors may result in such investors reducing their investment in the Corporation or not investing in the Corporation at all. Any reduction in the investor base interested or willing to invest in the oil and gas industry and more specifically, the Corporation, may result in limiting the Corporation's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Common Shares.

Expansion into New Activities

In the future, Lycos may acquire or move into new industry related activities or new geographical areas, may acquire different energy related assets, and as a result may face unexpected risks or alternatively, significantly increase Lycos's exposure to one or more existing risk factors, which may in turn result in Lycos's future operational and financial conditions being adversely affected.

Forward Looking Information May Prove to be Inaccurate

Investors are cautioned not to place undue reliance on 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 herein under the heading "*Special Note Regarding Forward Looking Statements*" above.

DIVIDENDS

The Corporation has not declared or paid any dividends for each of the three most recently completed financial years. It is the intention of the Corporation to retain any earnings to finance the growth and development of the Corporation's business, and, therefore the Corporation does not anticipate paying any dividends in the immediate or foreseeable future.

DESCRIPTION OF SHARE CAPITAL

As of the date hereof, Lycos is authorized to issue an unlimited number of Common Shares and an unlimited of preferred shares, of which 318,147,806 Common Shares and nil preferred shares are issued and outstanding.

Common Shares

The holders of Common Shares are entitled to dividends as and when declared by the Board, a right to one vote per Common Share at meetings of the Shareholders and, upon liquidation, to share in the remaining assets of Lycos as are distributable to such holders.

Preferred Shares

Preferred shares may be issued by the Corporation from time to time in one or more series and the Board may fix the number of preferred shares which is to comprise each series and the designation, rights, privileges, restrictions and conditions attaching to each such series. The preferred shares of each series shall, with respect to the payment of dividends and the distribution of assets or return of capital in the event of liquidation, dissolution or winding-up of the Corporation be entitled to preference over the Common Shares.

Options

The Corporation has a stock option plan under which options to purchase Common Shares may be granted to officers, directors, employees and consultants. The Board has approved a policy of reserving up to 10% of the outstanding Common Shares for issuance to eligible participants. Under the stock option plan, and in accordance with the policies of the TSXV, the maximum term of options issued may not exceed 10 years.

Warrants

As of the date hereof, the only outstanding Warrants are the Warrants issued pursuant to the Unit Private Placement. For more information regarding the terms of the Warrants, please see "*General Development of the Business – Three Year History – Financial Year Ended December 31, 2022*".

MARKET FOR SECURITIES AND TRADING HISTORY

The Common Shares commenced trading on the TSX-V under the symbol "LCX" on December 15, 2022, following the closing of the Business Combination. Prior to this date, the Common Shares were listed on the TSX-V under the symbol "SCD". The following table sets forth the price range and trading volume of the Common Shares (presented on a post-Consolidation basis) as reported by the TSX-V for the periods indicated.

Period	High ($)	Low ($)	Volume
January 2022	0.76	0.52	24,000
February 2022	0.76	0.76	0
March 2022	0.76	0.76	5,010
April 2022	0.76	0.76	111
May 2022	0.52	0.76	1,500
June 2022	0.64	0.40	96,000
July 2022	0.40	0.40	0
August 2022	0.40	0.40	1,000
September 2022	0.32	0.24	3,033
October 2022	0.32	0.32	66
November 2022	2.16	0.64	651,835
December 2022	0.90	0.40	6,881,169

PRIOR SALES

During the year ended December 31, 2022, the Corporation did not issue any securities that are outstanding but not listed or quoted on a marketplace other than as set forth below. All numbers presented below are presented on a post-Consolidation basis.

Date of Issuance	Class of Securities	Number of Securities Issued	Issue Price
December 12, 2022	Warrants	45,650,018 (1)(2)	$0.28
June 15, 2022	Options	137,500 (3)	$0.40

Notes:

(1) On December 12, 2022, in connection with the closing of the Business Combination, and pursuant to the Units issued under the Unit Private Placement, the Corporation issued 42,857,158 Warrants (presented on a post-Consolidation basis).

(2) On December 12, 2022, in connection with the closing of the Business Combination, the Corporation issued 2,792,860 Warrants to certain advisors to the Business Combination as compensation securities.

(3) On June 15, 2022, Samoth (predecessor to the Corporation) granted an aggregate of 137,500 options to purchase Common Shares to certain directors and officers pursuant to the Corporation's stock option plan. These options had an exercise price of $0.40 per Common Share and vested immediately. These options were all exercised or surrendered in connection with the closing of the Business Combination.

DIRECTORS AND OFFICERS

The name, municipality of residence, shareholdings and principal occupation for the past 5 years of each of the Corporation's directors and senior officers are as follows. The term of office for each director named below will expire at the next annual meeting of shareholders of the Corporation.

Name, Residence and Position	Director Since	Principal Occupation During the Last Five Years
David Burton *Calgary, Alberta* Director, President and Chief Executive Officer	December 12, 2022	Mr. Burton has more than 27 years of experience in the upstream oil and gas industry in all facets of petroleum engineering work including reservoir engineering, evaluations, secondary and tertiary recovery, unconventional oil and gas, area development and acid gas projects including work on CO2 sequestration in coals. He has had numerous executive roles and been involved in founding multiple successful start up energy companies. Prior to founding Chronos, Mr. Burton was a co-founder at Raging River Exploration Inc. ("Raging River") and Wild Stream Exploration Inc. ("Wild Stream"). Mr. Burton is a professional engineer and a member of the Alberta Association of Professional Engineers and Geoscientists of Alberta. Mr. Burton holds degrees in Petroleum Engineering from the University of Alberta (BSc) and a Master of Engineering degree in Chemical and Petroleum Engineering from the University of Calgary.
Kyle Boon(4) *Calgary, Alberta* Chief Operating Officer	N/A	Mr. Boon has 20 years' experience in the Western Canadian oil and gas sector. Mr. Boon most recently was a Founder and the Drilling and Completions Manager of Raging River and prior thereto held the role of Senior Production Technologist at Wild Stream. Mr. Boon holds a Petroleum Engineering Technology Diploma from the Northern Alberta Institute of Technology and is a member of the Association of Science & Engineering Technology Professionals of Alberta (ASET).
Lindsay Goos *Calgary, Alberta* Vice-President, Finance and Chief Financial Officer	N/A	Ms. Goos has 20 years of experience in the oil and gas industry in the disciplines of finance, financial reporting, budgeting, accounting, management, treasury, tax and business development. Previously, Founder, VP Finance & CFO of Imaginea Energy Ltd. and prior thereto Controller of BlackShire Energy Ltd. Ms. Goos began her professional career with KPMG LLP and has held progressively senior roles at various other oil and gas companies. Ms. Goos is a member of the Chartered Professional Accountants of Alberta and is a Chartered Professional in Human Resources of Alberta. Ms. Goos holds a Bachelor of Commerce and Arts degree from the University of Saskatchewan.
Jamie Conboy *Calgary, Alberta* Vice President, Exploration	N/A	Jamie Conboy is professional geologist, most recently working as subsurface lead with Bison Low Carbon Ventures (CCS) and formerly as founding member of the Storm Group of companies for 20 years in capacities of Vice President Geoscience and Chief Geologist. In his previous 12 years in the industry Mr. Conboy has worked on a variety of properties and play types at Canadian Hunter Exploration Ltd, Renaissance Energy Ltd. and Pinnacle Resources Ltd, among others. Mr. Conboy is a registered Professional Geologist and Responsible Member of APEGA in the Province of Alberta and holds a B.Sc. (Honours) in Geology from Queen's University (1992).
Barret Henschel(4) *Calgary, Alberta* Vice President, Production	N/A	Mr. Henschel has 13 years' experience in the oil and gas industry. Mr. Henschel joined the organization in January 2023 as Operations Manager. Prior to joining Lycos, Mr. Henschel was the Manager of Development – Light Oil at Baytex Energy Inc. and prior thereto was a Senior Area Engineer at Raging River Exploration. Mr. Henschel is a Professional Engineer and a member of the Association of Professional Engineers and Geoscientists of Alberta, holding a degree in Mechanical Engineering, with a Petroleum Minor from the University of Calgary.
Jeff Rideout *Calgary, Alberta* Vice President, Land	N/A	Mr. Rideout has over 20 years of experience in the oil and gas industry in the disciplines of commercial negotiations, acquisitions and divestitures in private, public and service companies. Mr. Rideout was previously a Senior Land/Commercial Negotiator with Whitecap Resources Inc., TORC Oil and Gas Ltd, and prior thereto Founder and Vice President Elkhorn Resources Inc. Jeff holds his Professional Landman (P.Land) designation and earned a Master of Business Administration (MBA) degree from The Haskayne School of Business, and a Bachelor of Arts (B.A.) degree from the University of Calgary.
Kevin Olson(2)(3) *Calgary, Alberta*	December 12, 2022	Mr. Olson has over 27 years of industry experience and is currently a director of Headwater Exploration Inc. ("**Headwater**"). Mr. Olson is a former board member of Raging River, Wild Stream, Wild River Resources Inc. ("**Wild River**") and Prairie

Name, Residence and Position	Director Since	Principal Occupation During the Last Five Years
Chair of the Board		Schooner Petroleum Ltd. Mr. Olson has served as a director of ten public companies and five private entities. Mr. Olson holds a Bachelor of Commerce degree majoring in finance and accounting from the University of Calgary.
Ian Atkinson(1)(2) *Calgary, Alberta* Director,	December 12, 2022	Mr. Atkinson has been the founder of several private and public oil and gas companies, with over 27 years of technical, executive and board of director experience. Mr. Atkinson has been President and CEO of Southern Energy Corp. (formerly Gulf Pine Energy Partners LP) since 2014. Prior thereto, Mr. Atkinson was a founder and Senior Executive Officer of Athabasca Oil Corporation.
Ali Horvath(2)(3) *Calgary, Alberta* Director	December 12, 2022	Ms. Horvath is the Vice President, Finance and Chief Financial Officer of Headwater. Ms. Horvath was previously a founder and the Controller of Raging River and prior thereto was a Senior Financial Accountant with Wild Stream. Ms. Horvath is a Chartered Professional Accountant and holds a Bachelor of Management degree from the University of Lethbridge.
Kel Johnston(1)(2) *Calgary, Alberta* Director	December 12, 2022	Mr. Johnston is currently CEO of Wylander Crude Corp, a firm that provides consultancy services to numerous oil and gas and private equity clients in Canada and the USA. He is also a Technical Advisor to Carbon Infrastructure Partners. Mr. Johnston has forty years of technical/financial/ ESG experience in the Canadian and Northern USA oil and gas sector, and capital markets experience from public companies to the oversight of private equity investments to leading edge carbon capture and storage knowledge. He has been directly involved in the conceptualization, discovery and exploitation of numerous oil and gas pools from the foothills of Alberta, BC and Montana to the plains of SE Saskatchewan. Mr.Johnston has maintained technical skills through ownership/active technical role in a private E&P company that holds interests in 2 CCUS projects. He has over thirty years of experience as a founder, executive and board member of numerous public and private oil and gas companies. Direct experience in a wide range of corporate activities including capital markets, private equity, ESG, mergers, sales/acquisition/strategic processes and IPOs. Mr. Johnston is a Professional Geologist and holds a Bachelor of Science (Hons.) degree in Geology from the University of Manitoba and a Master's degree in Economics from the University of Calgary.
Bruce Beynon(1) *Calgary, Alberta* Director	December 12, 2022	Mr. Beynon is a professional geologist with over 30 years of oil and gas industry experience. Mr. Beynon is currently the President of Tiburon Exploration Corp., a private consulting company. Prior thereto, Mr. Beynon was Executive Vice President, Exploration and Corporate Development at Baytex Energy Corp. Prior to the merger between Baytex and Raging River, Mr. Beynon held several positions with Raging River including President, Executive Vice President and Vice President, Exploration. Mr. Beynon graduated with a Bachelors and Masters of Science degree in Geology from the University of Alberta. Mr. Beynon serves on the Board of Southern Energy Corp., a TSXV listed company with focused operations in the southeast Gulf States of the US.
Don Cowie(3) *Calgary, Alberta* Director	December 12, 2022	Mr. Cowie was the founding Partner of JOG in 2002 and was the President of the firm from its inception until November 2016. Mr. Cowie was the Chairman of the Investment Committee of JOG from November 2016 until his retirement in December 2017. Since his retirement from JOG in December 2017, Mr. Cowie was a significant shareholder of JOG (now Carbon Infrastructure Partners) and sat on the board of several of its portfolio companies. Mr. Cowie no longer has any interest in Carbon Infrastructure Partners or JOG. Prior to founding JOG, Mr. Cowie was the head of Energy Investment Banking for Bank of America in Calgary, and prior thereto was one of the founders and directors of two junior oil and gas companies.

Notes:

1. Messrs. Ian Atkinson (Chair), Bruce Beynon and Kelvin Johnston form Lycos's Reserves, Health, Safety and Environment Committee.
2. Messrs. Kelvin Johnston (Chair), Kevin Olson, Ian Atkinson and Ms. Ali Horvath form Lycos's Corporate Governance and Compensation Committee.
3. Ms. Ali Horvath (Chair) and Messrs. Don Cowie and Kevin Olson form Lycos's Audit Committee.
4. On April 3, 2023, Mr. Kyle Boon was promoted from Vice President, Operations to Chief Operating Officer and Mr. Barret Henschel was promoted from Operations Manager to Vice President, Production.

As of the date hereof, the directors and officers of the Corporation as a group, beneficially own, or exercise control or direction over, an aggregate of approximately 79,821,906 Common Shares representing approximately 25.1% of the issued and outstanding Common Shares.

The information as to Common Shares beneficially owned, directly or indirectly or over which control or direction is exercised, is based upon information furnished to the Corporation by each of the individuals listed above.

Corporate Cease Trade Orders

To the knowledge of management of the Corporation, no director or officer of Lycos, has, within ten years before the date hereof, been a director, chief executive officer or chief financial officer of any company that:

(a) was subject to an order (as defined below) that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or

(b) was subject to an order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

For the purposes of the above section, "order" means a cease trade order, an order similar to a cease trade order, or an order that denied the relevant company access to any exemption under securities legislation, that was in effective for a period of more than 30 consecutive days.

Bankruptcies

To the knowledge of management of the Corporation, no director, executive officer, or shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation:

(a) is, at the date hereof, or has been within the 10 years before the date hereof, a director or executive officer of any company that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangements or compromise with creditors or had a receive, receiver manager or trustee appointed to hold its assets; or

(b) has within the 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 the assets of the director, executive officer or shareholder.

Penalties or Sanctions

To the knowledge of management of the Corporation, no director, executive officer, or shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, has been subject to:

(a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or

(b) any other penalties or sanctions imposed by a court or regulatory body, including a self-regulatory body, that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

There are potential conflicts of interest to which some of the directors or officers of Lycos will be subject in connection with the operations of Lycos. Some of the directors or officers are engaged in and will continue to be engaged in companies or businesses which may be in competition with the business of Lycos. Accordingly, situations may arise where some or all of the directors or officers will be in direct competition with Lycos. Conflicts, if any, will be subject to the procedures and remedies as provided under the ABCA. See also "*Risk Factors*".

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

To the knowledge of management of the Corporation, there are no legal proceedings or regulatory actions material to the Corporation to which the Corporation is a party, or was a party to during the most recently completed financial year, or of which any of its properties is the subject matter, or was the subject matter of during the most recently completed financial year, nor are there any such proceedings known to the Corporation to be contemplated. There have been no penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority and the Corporation has not entered to any settlement agreements with a court or securities regulatory authority.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as provided below, there are no material interests, direct or indirect, of directors or executive officers of the Corporation, or any shareholder who beneficially owns, directly or indirectly, or exercises control or direction over more than 10% of the outstanding Common Shares, or any other Informed Person (as defined in NI 51-102) or any known associate or affiliate of such persons, in any transaction within the three most recently completed financial years or during the current financial that has materially affected or would materially affect the Corporation or any of its subsidiaries.

Sanjib Gill, the Corporate Secretary of the Corporation, is a partner of the national law firm Stikeman Elliott LLP, which law firm rendered legal services to the Corporation.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar of the Corporation is Odyssey Trust Corporation, 1230 – 300 5th Avenue S.W., Calgary, Alberta T2P 3C4.

MATERIAL CONTRACTS

The Corporation has not entered into any material contracts within the most recently completed financial year or before the most recently completed financial year which are still in effect, other than contracts entered into in the ordinary course of business.

INTERESTS OF EXPERTS

Reserves estimates contained in this AIF were derived from the Reserves Report prepared by Sproule, an independent reserves evaluator. As of December 31, 2022, to the knowledge of management of the Corporation, the directors, officers, employees and consultants of Sproule who participated in the preparation of the Reserves Report who were in a position to directly influence the preparation or outcome of the preparation of the Reserves Report as a group, owned, directly or indirectly, less than 1% of the outstanding Common Shares. In addition, none of the officers, directors, employees or consultants of Sproule are currently expected to be elected, appointed or employed as a director, officer or employee of Lycos or any of the Corporation's associates or affiliates.

KPMG is the auditor of the Corporation and has confirmed that it is independent with respect to Lycos within the meaning of the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta.

Crowe Mackay LLP is the previous auditor of the Corporation and has confirmed that it is independent within the meaning of the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta.

Other than as set out above, no other experts (whose profession or business gives authority to a report, valuation, statement or opinion made by them) were named in any securities disclosure document filed by the Company pursuant to NI 51-102 in the most recently completed financial year.

ADDITIONAL INFORMATION

Additional information relating to the Corporation can be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans will be contained in the Corporation's management information circular relating to the annual meeting of shareholders being held on June 14, 2023. Additional financial information is contained in the Corporation's financial statements and the related management's discussion and analysis for the year ended December 31, 2022.

Additional copies of this AIF and the materials listed in the preceding paragraph are available on SEDAR at www.sedar.com and upon request by contacting the Corporation at its offices at 215 – 2nd Street SW, Suite 1900, Calgary, Alberta T2P 2Z1 or by phone at 403-453-1950.

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

To the Board of Directors of Lycos Energy Inc. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2022. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2022, estimated using forecast prices and costs.

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

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

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

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2022, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date	Location of Reserves (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited (M$)	Evaluated (M$)	Reviewed (M$)	Total (M$)
Sproule	December 31, 2022	Canada				
Total			**Nil**	**118,992**	**Nil**	**118,992**

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

7. We have no responsibility to update our report referred to in paragraph 5 for events and circumstances occurring after the effective date of our report, entitled "Evaluation of the P&NG Reserves of Lycos Energy Inc. (As of December 31, 2022)".

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

Executed as to our report referred to above:

SPROULE ASSOCIATES LIMITED

Calgary, Alberta

Date: March 15, 2023

(signed) "Jeffrey "

Jeffrey McKeeman, P. Eng.
Team Lead, Engineering

(signed) "Gary R. Finnis"

Gary R. Finnis, P. Eng.
Senior Manager, Engineering

FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS
ON RESERVES DATA AND OTHER INFORMATION

Management of Lycos Energy Inc. (the "**Corporation**") is responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

Sproule is an independent qualified reserves evaluators, has evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluators will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of the Corporation has:

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

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

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

The Reserves Committee of the board of directors of the Corporation has reviewed the Corporation'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 of the Corporation has, on the recommendation of the Reserves Committee, approved:

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

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluators 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) *"Dave Burton"*	(signed) *"Jamie Conboy"*
Dave Burton President & Chief Executive Officer	**Jamie Conboy** Vice President, Exploration
(signed) *"Ian Atkinson"*	(signed) *"Kevin Olson"*
Ian Atkinson Director & Chair of the Reserves Committee	**Kevin Olson** Director & Chair of the Board

April 27, 2023