GEAR ENERGY

ANNUAL INFORMATION FORM

for the year ended December 31, 2022

March 24, 2023

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ABBREVIATIONS

Crude Oil and Natural Gas Liquids		Natural Gas	
bbl	one barrel	Mcf	one thousand cubic feet
Bbl	barrels	Mcfe	one thousand cubic feet of natural gas equivalent on the basis of 6 Mcfe for 1 bbl of oil (unless otherwise indicated)
bbl/d	barrels per day	MMcf	one million cubic feet
Mbbl	thousand barrels	Bcf	one billion cubic feet
BOE	barrels of oil equivalent of natural gas on the basis of 1 BOE for 6 Mcf of natural gas (unless otherwise indicated)	Mcf/d	one thousand cubic feet per day
MBOE	one thousand barrels of oil equivalent	MMcf/d	one million cubic feet per day
MMBOE	one million barrels of oil equivalent	GJ	gigajoule
BOE/d	barrels of oil equivalent per day	GJs/d	gigajoules per day
NGL	natural gas liquids	Btu	British thermal unit
Stb	standard stock tank barrel	MMbtu	million British thermal units

BOEs or Mcfe may be misleading, particularly if used in isolation. A BOE or Mcfe conversion ratio of six Mcf to one bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. This conversion factor is an industry accepted norm and is not based on either energy content or current prices. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6 Mcf:1 bbl, utilizing a conversion on a 6 Mcf:1 bbl basis may be misleading as an indication of value.

Other

AECO	Rockpoint Gas Storage Canada Ltd.'s natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale
m^3	cubic metres
$000's	thousands of dollars
WCS	Western Canadian Select, the standard reference for heavy blended crude, price paid at Hardisty, Alberta
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

CONVERSIONS

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

To Convert From	To	Multiply By
Mcf	thousand cubic metres ("**10^3m^3**")	0.0282
thousand cubic metres	Mcf	35.494
bbl	cubic metres ("**m^3**")	0.159
cubic metres	bbl	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

CERTAIN DEFINITIONS

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

"**ABCA**" means the *Business Corporations Act*, R.S.A. 2000, c. B-9, as amended, including the regulations promulgated thereunder;

"**Amended and Restated Convertible Debenture Indenture**" means the amended and restated convertible debenture indenture dated November 30, 2020 between the Corporation and Computershare Trust Company of Canada governing the terms of the Convertible Debentures, which amended and restated the Original Convertible Debenture Indenture;

"**BMEC**" means Black Mountain Energy Corporation, a corporation incorporated under the laws of Alberta which was amalgamated with Old Gear on May 1, 2010;

"**BMEC Acquisition**" means the offer of BMEC to purchase all of the issued and outstanding class A common shares of Old Gear from the shareholders of Old Gear in exchange for 1.4 common shares of BMEC and 0.258125 non-voting preferred shares of BMEC for each class A common share of Old Gear outstanding;

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

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

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

"**Convertible Debentures**" means the 7.00% convertible unsecured subordinated debentures due November 30, 2023 of Gear;

"**Corporation**" or "**Gear**" means Gear Energy Ltd., a corporation amalgamated under the laws of the Province of Alberta;

"**COVID-19**" means the novel coronavirus pandemic;

"**Credit Facilities**" means the credit facilities with a syndicate of lenders led by ATB Financial entered into by Gear from time to time and as amended and supplemented from time to time;

"**Gross**" means:

(a) in relation to an entity's interest in production and reserves, its "company gross reserves", which are such entity's working interest (operating and non-operating) before deduction of royalties and without including any royalty interest of such entity;

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

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

"**NCIB**" has the meaning ascribed to it in the section "*General Development of the Business – Three Year History – Year Ended December 31, 2022*";

"**Net**" means:

(a) in relation to an entity's interest in production and reserves, such entity's interest (operating and non-operating) after deduction of royalties obligations, plus the entity's royalty interest in production or reserves;

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

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

"**NI 51-101**" means National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* adopted by the Canadian Securities Administrators;

"**NI 51-102**" means National Instrument 51-102 – *Continuous Disclosure Obligations* adopted by the Canadian Securities Administrators;

"**Old Gear**" means Gear Energy Ltd., a corporation incorporated under the laws of Alberta which was amalgamated with BMEC on May 1, 2010;

"**OPEC**" means the Organization of the Petroleum Exporting Countries;

"**Options**" means options to purchase Common Shares granted under the share option plan of the Corporation;

"**Original Convertible Debenture Indenture**" means the convertible debenture indenture dated November 30, 2015 between the Corporation and Computershare Trust Company of Canada governing the terms of the Convertible Debentures;

"**Preferred Shares**" means preferred shares, issuable in series, in the capital of Gear;

"**SEDAR**" means the System for Electronic Document Analysis and Retrieval, accessible at www.sedar.com;

"**Series 1 Preferred Shares**" means the authorized Series 1 preferred shares in the capital of Gear;

"**Sproule**" means Sproule Associates Limited, independent oil and natural gas reservoir engineers of Calgary, Alberta;

"**Sproule Report**" means the independent engineering evaluation of Gear's oil, natural gas liquids and natural gas interests prepared by Sproule effective December 31, 2022 and dated February 8, 2023;

"**Steppe**" means Steppe Resources Inc., a corporation incorporated under the laws of the Province of Alberta which was amalgamated with Gear on September 18, 2018;

"**Steppe Arrangement**" means the acquisition by Gear of all the issued and outstanding common shares of Steppe pursuant to a plan of arrangement under the ABCA whereby shareholders of Steppe received 0.1445 of a Common Share for each share of Steppe;

"**Steppe Petroleum**" means Steppe Petroleum Inc., a corporation incorporated under the laws of the Province of Alberta which was amalgamated with Gear on January 1, 2019;

"**Steppe (USA)**" means Steppe Petroleum (USA) Inc., a corporation incorporated under the laws of the State of Delaware, and a wholly-owned subsidiary of the Corporation as a result of the January 1, 2019 amalgamation between Gear and Steppe Petroleum;

"**Striker**" means Striker Exploration Corp. a corporation amalgamated under the laws of Alberta which was amalgamated with Gear on July 29, 2016;

"**Striker Arrangement**" means the acquisition by Gear of all the issued and outstanding common shares of Striker pursuant to a plan of arrangement under the ABCA whereby shareholders of Striker received 2.325 Common Shares for each share of Striker;

"**Tax Act**" means the *Income Tax Act* (Canada), R.S.C. 1985, c. 1 (5^{th} Supp.), as amended, including the regulations; and

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

CONVENTIONS

Certain terms used herein are defined under the heading "*Certain Definitions*".

Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars.

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

Unless otherwise specified, information in this Annual Information Form is as at the end of the Corporation's most recently completed financial year, being December 31, 2021.

READER ADVISORY REGARDING FORWARD-LOOKING STATEMENTS

Certain of the statements contained herein including, without limitation, the financial and business prospects and financial outlook, Gear's strategy to attempt to enhance returns on its assets, Gear's strategy to achieve growth, Gear's expected acquisition criteria, reserve and production estimates, details of Gear's capital budget, expected exploration and development activities, expected timing for developing undeveloped reserves, drilling and re-completion plans, timing of drilling, re-completion and tie-in of wells, expected plans to test Gear's emergency response plan, expected abandonment and reclamation activities, expected future abandonment and reclamation obligations, productive capacity of wells, details of capital expenditure activity and the timing thereof, the effect of government announcements, proposals and legislation, plans regarding hedging, expected or anticipated production rates, timing of expected production increases, weighting of production between different commodities, expected commodity prices, Gear's dividend policy, price differentials, exchange rates, production expenses, transportation costs and other costs and expenses, maintenance of productive capacity and capital expenditures and methods of financing thereof, may be forward-looking statements or forward-looking information (collectively, "**forward-looking statements**"). Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and similar expressions may be used to identify these forward-looking statements. These forward-looking statements reflect management's current beliefs and are based on information currently available to management. Forward-looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements including, but not limited to, risks associated with volatility of commodity prices, oil and gas exploration, development, exploitation, production, changes to the Corporation's capital budget, marketing and transportation, loss of markets, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals, ability to access sufficient capital from internal and external sources, risks relating to the Corporation's ability to repay amounts outstanding under the Credit Facilities when, and if, required, risks associated with public health risks and the risk factors outlined under "*Risk Factors*" and elsewhere herein. The recovery and reserve estimates of the Corporation's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

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

Corporation operates; and the ability of the Corporation to successfully market its oil and natural gas products.

Readers are cautioned that the foregoing list of factors is not exhaustive. Although the forward-looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward-looking statements. Investors should not place undue reliance on forward-looking statements. These forward-looking statements are made as of the date hereof and the Corporation assumes no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

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

CORPORATE STRUCTURE

Name, Address and Incorporation

Gear is a Canadian exploration and production company with heavy and light oil production in central Alberta, west central and southeast Saskatchewan and British Columbia.

Gear was incorporated on June 25, 2007 under the ABCA as "Black Mountain Energy Corporation". On January 29, 2010, BMEC acquired all of the issued and outstanding common shares of Old Gear pursuant to the BMEC Acquisition. BMEC and Old Gear amalgamated on May 1, 2010 and continued under the name "Gear Energy Ltd."

On June 3, 2010, Gear amended its articles to: (i) consolidate the Common Shares on the basis of one post-consolidation Common Share for every five pre-consolidation Common Shares; and (ii) to convert the then-issued and outstanding Series 1 Preferred Shares to Common Shares on the basis of one post-consolidation Common Share for every five pre-consolidation Series 1 Preferred Shares.

Gear was amalgamated under the provisions of the ABCA on September 21, 2011 with its wholly-owned subsidiary, Lift Resources Inc., and continued under the name "Gear Energy Ltd."

Pursuant to the Striker Arrangement, Gear was amalgamated with Striker on July 27, 2016, and continued under the name "Gear Energy Ltd."

Pursuant to the Steppe Arrangement, Gear was amalgamated with Steppe on September 18, 2018, and continued under the name "Gear Energy Ltd."

Gear was then amalgamated under the provisions of the ABCA on January 1, 2019 with its wholly-owned subsidiary, Steppe Petroleum, and continued under the name "Gear Energy Ltd." As a result, Steppe (USA), a corporation incorporated under the laws of the State of Delaware, U.S.A and formerly a direct and wholly-owned subsidiary of Steppe Petroleum, is now a direct and wholly-owned subsidiary of Gear. Other than Steppe (USA), Gear has no subsidiaries.

The head office of Gear is located at Suite 800, 205 – 5th Avenue S.W., Calgary, Alberta T2P 2V7 and its registered office is located at Suite 2400, 525 – 8th Avenue S.W., Calgary, Alberta T2P 1G1.

GENERAL DEVELOPMENT OF THE BUSINESS

Three Year History

The following is a summary of the significant events in the development of the Corporation's business over the last three completed financial years.

Year Ended December 31, 2020

On July 10, 2020, the borrowing base of the Credit Facilities was reduced from $90 million to $75 million. The Credit Facilities on such date were comprised of a $42.5 million syndicated revolving term credit facility, a $25 million syndicated non-revolving term facility and a $7.5 million operating credit facility. In conjunction with the redetermination of the borrowing base, the revolving period was extended until August 31, 2020 and was extendible for 364 days with the consent of the lenders. Unless extended, the Credit Facilities were scheduled to mature on May 28, 2021. In addition, there were three mandatory repayment dates and corresponding reductions of the borrowing base scheduled for September 30, 2020, December 31, 2020, and March 31, 2021 of $5 million each.

On November 30, 2020, Gear entered into the Amended and Restated Convertible Debenture Indenture that amended and restated the Original Convertible Debenture Indenture. Under the Amended and Restated Convertible Debenture Indenture, the terms of the Convertible Debentures were amended to increase the interest rate per annum from 4.0% to 7.0%, reduce the conversion price from $0.87 to $0.32 per Common Share, allow Gear to pay interest-in-kind by issuing additional Convertible Debentures for the period from December 1, 2020 through November 30, 2021 and extend the maturity date from November

30, 2020 to November 30, 2023. The amendments to the Convertible Debentures were approved by the requisite majority of holders of Convertible Debentures in accordance with the terms of the Original Convertible Debenture Indenture and, in addition, at a special meeting of Gear shareholders held on December 16, 2020, Gear shareholders approved the amendments to the terms of the Convertible Debentures. See "*Description of Capital Structure – Convertible Debentures*" for additional details regarding the Convertible Debentures.

On December 18, 2020, Gear received approval for the extension of its Credit Facilities maturity date to May 27, 2022 with a borrowing base of $70 million. Similar to the previous renewal, under the terms of the extension the borrowing base was reduced by an incremental $5 million on December 31, 2020 and will be further reduced by an additional $5 million on March 31, 2021. The next annual borrowing base redetermination is scheduled for May 31, 2021.

During the year-ended December 31, 2020, 1.1 million Common Shares with an aggregate value of $0.5 million were repurchased pursuant to a normal course issuer bid that commenced on September 25, 2019.

Total capital spending in 2020, including net acquisitions, was $12.4 million. The majority of these funds were spent to drill 9 Gross (9 Net) oil wells with a 100% success rate**.** The 2020 drilling program focused on multiple areas including Paradise Hill, Lindbergh, Frenchman's Butte, Killam and Provost.

Year Ended December 31, 2021

On March 23, 2021, the holder of $9.3 million of Gear's outstanding Convertible Debentures elected to convert its Convertible Debentures at a conversion price of $0.32 per Common Share resulting in the issuance by Gear of 29.2 million Common Shares. Following such conversion and as at March 23, 2021, $3.4 million Convertible Debentures remained outstanding.

On April 26, 2021, in accordance with the terms and conditions of the Amended and Restated Convertible Debenture Indenture, Gear redeemed its outstanding Convertible Debentures in exchange for Common Shares issued at a price of $0.49 per Common Share (the "**Redemption Issuance Price**"). Holders of Convertible Debentures who did not elect to convert their Convertible Debentures received approximately 2,041 Common Shares for each $1,000 principal amount of Convertible Debentures held. The accrued and unpaid interest on the Debentures up to, but excluding, the date of redemption was paid in cash. Pursuant to the terms of the Convertible Debentures, the Redemption Issuance Price was calculated based on 95% of the volume weighted average trading price of the Common Shares on the TSX for the 20 consecutive trading days ending on April 19, 2021. Each holder of Convertible Debentures had the right to convert their Convertible Debentures into Common Shares at a conversion price of $0.32 per Common Share at any time on or prior to April 23, 2021. Holders of Convertible Debentures who elected to convert the principal amount of their Convertible Debentures received 3,125 Common Shares for each $1,000 principal amount of Convertible Debentures converted plus a cash payment for accrued unpaid interest up to, but excluding, the date of conversion.

On June 23, 2021, Gear received approval for the extension of its Credit Facilities maturity date to May 27, 2023 with a borrowing base of $53.1 million. Similar to the previous renewal, under the terms of the extension the borrowing base was reduced by an incremental $5 million on September 30, 2021 and was scheduled to be further reduced by an additional $6.9 million on May 27, 2022.

On November 5, 2021, Gear completed its semi-annual borrowing base review and increased its borrowing base from $41.15 million to $42.0 million. In addition, on such date Gear early repaid the $6.9 million portion of the Credit Facilities that was due on May 27, 2022. The next borrowing base review is expected to be completed on or about May 31, 2022.

Total capital spending in 2021, including net acquisitions, was $28.8 million. The majority of these funds were spent to drill 20 Gross (18.7 Net) oil wells with a 100% success rate**.** The 2021 drilling program focused on multiple areas including Paradise Hill, Wildmere, Wilson Creek, Provost and SE Saskatchewan.

Year Ended December 31, 2022

On May 4, 2022, Gear announced the initiation of a quarterly variable cash dividend program with an initial dividend of $0.01 per Common Share to be paid on May 30, 2022 to Gear shareholders of record as of May 16, 2022.

On May 4, 2022, the Corporation announced the TSX approved a normal course issuer bid (the "**NCIB**") pursuant to which Gear would be able to repurchase for cancellation its Common Shares through the facilities of the TSX. The NCIB commenced on May 9, 2022 and will terminate on the earlier of: (i) the date on which Gear has acquired all Common Shares sought pursuant to the NCIB; or (ii) May 8, 2023, unless terminated earlier at the option of the Corporation upon prior notice being given to the TSX. Pursuant to the NCIB, Gear may purchase for cancellation up to 24,029,161 Common Shares (approximately 10% of its then issued and outstanding Common Shares) for a one year period at prevailing market prices at the time of purchase. The total number of Common Shares Gear is permitted to purchase is subject to a daily purchase limit of 551,916 Common Shares (representing 25% of the average daily trading volume of 2,207,667 Common Shares on the TSX calculated for the six-month period ended April 30, 2022); however, Gear can make one block purchase per calendar week that exceeded the daily purchase restrictions. For the period ended December 31, 2022, 3.6 million Common Shares with an aggregate value of $5.3 million were repurchased pursuant to the NCIB. The Common Shares purchased were purchased by a registered broker through the facilities of the TSX and other alternative Canadian trading platforms at the time of such transaction.

On July 27, 2022, Gear announced the implementation of a monthly dividend of $0.01 per Common Share replacing the previously announced quarterly variable cash dividend.

In April 2022, Gear completed its semi-annual borrowing base review for its Credit Facilities extending the maturity date to May 25, 2024 with no changes to the borrowing base. In October 2022 Gear completed its fall semi-annual borrowing base redetermination with no changes to its Credit Facilities. The next borrowing base review for the Credit Facilities is expected to be complete on or before May 31, 2023.

Total capital spending in 2022, including net acquisitions, was $50.5 million**.** The majority of these funds were spent to drill 24 Gross (24 Net) oil wells with a 96% success rate. The 2022 drilling program focused on multiple areas including Provost, Killam, Wildmere, Lindbergh, Maidstone, Celtic and SE Saskatchewan.

Total distributions of dividends in 2022 was $18.2 million, a total of $0.07/share.

Significant Acquisitions

There were no significant acquisitions completed by the Corporation during its most recently completed financial year for which disclosure is required under Part 8 of NI 51-102.

DESCRIPTION OF THE BUSINESS

General

Gear is a Calgary, Alberta based junior Canadian crude oil and natural gas exploration and production company. All of the Corporation's oil and gas properties are located in Alberta, British Columbia and Saskatchewan. The Corporation currently has core holdings in central Alberta and west central and southeast Saskatchewan. The Corporation has a significant land position in Alberta and Saskatchewan and intends to continue to evaluate additional oil and gas assets in Alberta and Saskatchewan.

Business Plan and Corporate Strategy

Gear's strategy is to provide long term production and cash flow growth on a per debt adjusted share basis as a low cost oil and gas operator. The Corporation's business plan contemplates that the Corporation will pursue exploration, development and exploitation drilling, complemented with property or corporate acquisitions exhibiting synergies in land, facilities, production and operating efficiencies.

Gear plans to achieve this growth by pursuing assets with the following characteristics:

- Geographically focused
- Definable resource base with low risk production
- Repeatable projects that are statistically economic
- Horizontally amenable producing horizons
- Easy surface access and existing infrastructure
- High operatorship percentage

See "*Risk Factors*".

Gear's strategy to attempt to enhance returns on its assets is by:

- Drilling and developing on controlled lands
- Focusing on operational and cost efficiencies
- Continually improving operations through innovation and imitation
- Adopting and refining advanced drilling and completing techniques
- Pursuing strategic acquisitions with significant potential synergies

In reviewing potential drilling or acquisition opportunities, Gear gives consideration to a variety of criteria, including: (i) the capital required to secure or evaluate the investment opportunity; (ii) if successful, the potential return on the project; (iii) the likelihood of success; (iv) the risk of return versus cost of capital; (v) the strategic benefits to Gear; and (vi) Gear's ability to operate a project.

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

In November of 2022, the Board approved a $61 million capital budget for 2023, targeting modest production growth, continued return to shareholders through Gear's monthly dividend program, maintenance of its strong balance sheet and continued commitment to improving Gear's environmental footprint through abandonment and reclamation activities. Under the approved capital budget for 2023, $39 million (64%) is expected to be focused on drilling 22 gross (22 net) wells including 15 Lloydminster area heavy oil wells, five Provost and Killam, Alberta medium oil wells, one light oil well in Wilson Creek, Alberta, and one Southeast Saskatchewan Tableland light oil well; $9 million (15%) is expected to be invested in water flood expansions and optimizations including continued expansion of various heavy oil water floods, continued expansion of the Killam medium oil water flood, expansion of the Tableland light oil water flood and further expansions of the light oil water floods in Wilson Creek; $7 million (11%) is expected to be directed to continued reduction in liabilities associated with abandonment and reclamations; and $6 million (10%) is expected to be invested in land, seismic, field capital projects, recompletions and other corporate costs.

The amount and allocation of capital the Corporation will expend for its 2023 exploration and development program and the nature of its expenditures may vary materially based on commodity prices, market access, transportation constraints, other industry conditions and the Corporation's drilling results as the year progresses. Access to additional capital may spur an expansion of the program; however, any significant reduction in commodity prices, any unexpected reduction in Gear's access to capital or any constraints on Gear's ability to transport and market its production may lead to a reduction in the Corporation's 2023 exploration and development program. Although Gear's management remains committed to the above strategy, various factors may impact Gear's ability to continue to pursue its business strategy. See "*Industry Conditions*" and "*Risk Factors*" for further details.

Specialized Skill and Knowledge

Gear believes that its team has all of the key components to successfully implement its business plan: strong technical skills; expertise in planning and financial controls; ability to execute on business development opportunities; capital markets expertise; extensive experience in crude oil and natural gas exploration and development in Western Canada; and an entrepreneurial spirit that allows Gear to effectively identify, evaluate and execute on value-added initiatives. See "*Directors and Executive Officers*".

Competitive Conditions

The crude oil and natural gas industry is intensely competitive in all its phases. Companies operating in the upstream petroleum industry must manage risks which are beyond the direct control of company personnel. Among these risks are those associated with exploration and development, commodity prices, foreign exchange rates, interest rates, environmental damages, market access and the current weakness impacting the crude oil and natural gas industry as a whole. See "*Risk Factors – Competition*".

Gear expects the intense level of competition to continue in the future. Gear competes with a substantial number of other entities, certain of which have greater technical or financial resources particularly when it comes to acquiring reserves, crude oil and natural gas mineral rights, skilled industry personnel, access to end user markets and capital to finance their activities. With the maturing nature of the Western Canadian Sedimentary Basin, access to new prospects is becoming more competitive and complex and Gear's ability to execute its business plan of growing its crude oil and natural gas reserves and cash flow will depend not only on the Corporation's ability to exploit and develop existing properties but also its ability to identify and acquire additional properties or prospects for exploratory and development drilling. Gear believes that its competitive position is equivalent to that of other crude oil and natural gas issuers of similar size and at a similar stage of development.

Cyclical Nature of Business

In general, the energy business is cyclical in nature and heavily dependent on macro-economic cycles. In periods of economic expansion and growth the demand for energy increases as economies build inventory and productive capacity. Generally, in periods of economic contraction or recession, the rate of growth in energy demand declines. These macroeconomic cycles often impact global, North American and local prices for commodities, particularly crude oil and natural gas prices. In addition, the actions of OPEC and other oil producing countries and other factors impacting supply of oil will impact the price of oil. See "*Risk Factors – Weakness and Volatility in the crude oil and natural gas Industry*".

Demand for heavy crude oil begins to increase in the spring time and peaks in the summer months as heavy crude oil is often the base feed stock which supply refineries that make end products such as transportation fuels, heating oils, and asphalt for road paving. During the fall, refiners switch from making gasoline for summer driving season and asphalt for paving season and enter turn around season creating temporary lower demand for heavy crudes while these refineries undergo maintenance and repairs. Demand picks up again through the winter with a focus on making heating fuels until the spring comes and refiners again switch to focus on building gasoline stocks for the summer season. Demand for light oil can also vary throughout the year, although not usually with the same volatility as heavy crude oil.

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

In anticipation of the operational delays associated with "spring break up", the Corporation takes certain steps to mitigate interruption to its activities including, scheduling drilling and completion activities to be completed before the spring break up season, setting up extra batteries to collect the crude oil and natural gas produced during such time, servicing pipelines and facilities to ensure they are in working order in the event access is limited. Through the duration of spring break up, drilling and exploratory activities slow and the Corporation's production which is not otherwise tied-in may be shut in temporarily if access is limited.

In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict the Corporation's ability to access its properties, cause operational difficulties including damage to machinery or contribute to personnel injury as a result of dangerous working conditions. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity (including temporary production shut-ins), damage to the Corporation's equipment or injury to its personnel. See "*Risk Factors – Seasonality*".

Environmental Considerations and Protection

The Corporation is required to comply with various federal, provincial and municipal laws related to climate change and protection of the environment. Compliance with such laws affect a variety of aspects of the Corporation's operations including, among others, abandonment and reclamation of wells, facilities and related infrastructure, flaring and venting of natural gas, water usage and disposal, greenhouse gas ("**GHG**") emissions and clean-ups of spills.

In addition to compliance with the abandonment and reclamation obligations under provincial legislation in Alberta, British Columbia and Saskatchewan, Gear believes in well abandonment and site restoration in a timely manner to ensure minimal damage to the environment and lower overall costs. As a result, Gear allocates a portion of its annual capital budget to such activities. During 2022, Gear invested approximately $6.3 million in the abandonment and reclamation of wells and related facilities and infrastructure. On April 17, 2020, the federal government announced that as part of its COVID-19 Economic Response Plan that it would provide $1.7 billion to clean up orphan and inactive wells in Alberta, Saskatchewan and British Columbia under a Site Rehabilitation Program. In 2020, Gear was approved for a total of $2.2 million of this funding; $0.1

million in British Columbia, $0.6 million in Saskatchewan and $1.5 million in Alberta. Gear carried over $1.6 million of funding from 2020 as the spending had yet to occur. In 2021, Gear was approved for a total of $3.8 million of this funding; $1.5 million in Saskatchewan and $2.3 million in Alberta. During 2022, Gear utilized $1.2 million from the program to extinguish liabilities by conducting abandonment and reclamation activities. Gear carried over $0.3 million of funding from 2022 as the spending had yet to occur. For further information relating to the abandonment and reclamation programs in Alberta, British Columbia and Saskatchewan and see "*Industry Conditions - Regulatory Authorities and Environmental Regulation – Liability Management Rating Program*".

The federal government and certain provincial governments have enacted legislation aimed at discouraging the use of fossil fuels in an effort to decrease GHG emissions. Over the long-term, laws designed to curb the use of fossil fuels in Canada and other countries could have an impact on the demand for fossil fuels and have a negative impact on the price of oil and natural gas, which would have an effect on the Corporation's financial results and ultimately the sustainability of the Corporation's business model. In the short-term, carbon taxes and other legislative measures designed to curb GHG emissions may adversely affect Gear's financial results as such taxes increase the costs of fuels used to operate Gear's machinery and vehicles; however, as Gear does not have any facilities that exceed current emissions thresholds that would subject Gear to more onerous requirements, the short, medium and long-term impacts of carbon taxes and similar measures are not expected to have a material effect on the Corporation's financial results. As at the date hereof, Gear's current emission levels are not subject to any climate change regulations. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*", "*Risk Factors – Climate Change*" and "*Risk Factors – Carbon Pricing Risk*".

Partially in response to legislative measures aimed at curbing flaring and venting of natural gas and the associated release of methane and other GHGs into the atmosphere, Gear strives to collect and market gas in order to decrease the volume that is flared or vented. In 2022, Gear spent approximately $2.9 million on transportation and other infrastructure to allow gas from its production to be collected and brought to market rather than such gas being vented or flared. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*", "*Risk Factors – Climate Change*" and "*Risk Factors – Carbon Pricing Risk*".

Gear undertakes waterflooding and fracking activities as part of its operations. The majority of the water is reused and recycled in the waterflood and completion activities; therefore, there is immaterial financial costs associated with disposal. Although minimal, Gear works to ensure the safe disposal of the fluids to avoid the contamination of ground water. In addition to the costs associated to waterflooding/fracking activities, Gear may from time to time have limited access to sufficient volumes of fluids or there may be restrictions imposed on such activities in the areas in which it operates which would have a negative effect on Gear's production volumes and revenues. See "*Risk Factors – Disposal of Fluids Used in Operations*" and "*Risk Factors – Waterflood*".

Although Gear operates in compliance with all applicable regulations and ensures that all staff and contractors employ sound practices to protect the environment and to ensure employee and public health and safety, occasionally fluid spills and other incidents threatening the environment may occur. The costs of cleaning up such spills could negatively affect the Corporation's financial and operating results as the Corporation has to incur costs and utilize resources in cleaning up such spills. In 2022, the Corporation experienced no material spills.

Health, Safety, Environmental and Social Policies

Gear's management, employees and all contractors are responsible and accountable for the overall health, safety and environmental program of the Corporation. Gear operates in compliance with all applicable regulations and ensures that all staff and contractors employ sound practices to protect the environment and to ensure employee and public health and safety.

Gear maintains a safe and environmentally responsible workplace and provides training, equipment and procedures to all individuals in adhering to its policies. It also solicits and takes into consideration input from neighbors, communities and other stakeholders in regard to protecting people and the environment.

At the field level, Gear has a corporate Environment Management System which is continuously updated and meets the regulatory guidelines. Procedures are put in place to ensure that the utmost care is taken in the day-to-day management of Gear crude oil and natural gas properties with an emphasis on incident prevention. In addition, Gear requires each of its field workers to have completed industry standard courses.

The Corporation also has Emergency Response Plans ("**ERPs**") which are prepared in accordance with applicable regulations. The ERPs are designed to provide the policies, practices and procedures to be implemented in the event of an emergency situation that arises at or as a result of Gear's operations, including but not limited to: a serious injury or fatality, fire or explosion, uncontrolled or hazardous product release and oil or hazardous chemical spill. The purpose of the ERPs is to protect the health, safety and welfare of the public and workers and minimize the potential adverse environmental effects. On an annual basis, Gear holds a functional tabletop ERP exercise in Alberta to test its understanding and effectiveness in the case of an actual emergency. Gear holds exercises annually to ensure that its staff and executives are ready should the need arise. Management intends to test the ERPs in 2022 to ensure their effectiveness and procedures are revised to ensure the Corporation is adhering to the highest industry standards.

The Board receives a report from management at each quarterly Board meeting outlining any environmental or safety incidents that occurred or areas of concern that have arisen since the last quarterly Board meeting. More significant incidents, if any, are discussed in greater detail and management and the Board consider whether any changes should be implemented as a result of the incident.

Employees

As at December 31, 2022, Gear had 32 employees with 22 staff in the Calgary office and 10 employees located in Gear's operating areas in Alberta and Saskatchewan. Gear also has a number of contract operators in the field.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated February 8, 2023. The effective date of the Statement is December 31, 2022 and the preparation date of the Statement is February 8, 2023.

Disclosure of Reserves Data

The Corporation engaged Sproule to provide an evaluation of the Corporation's proved and proved plus probable reserves as at December 31, 2022. The reserves data set forth below (the "**Reserves Data**") is based upon the Sproule Report. The Reserves Data summarizes the crude oil, natural gas liquids and natural gas proved and probable reserves of the Corporation and the net present values of future net revenue for these reserves using forecast prices and costs. The Sproule Report has been prepared in accordance with the standards and the reserve definitions contained in the COGE Handbook and NI 51-101. The Reserves Committee of the Board has reviewed and approved the Sproule Report and this statement. The Report on Reserves Data by the Independent Qualified Reserves Evaluator and the Report of Management and Directors on Oil and Gas Disclosure are attached as Schedules "A" and "B" hereto, respectively.

All of the Corporation's reserves are in Canada and, specifically, in the Provinces of Alberta, British Columbia and Saskatchewan.

All evaluations of future net production revenue set forth in the tables below are based on forecast prices and costs and are after direct lifting costs and future capital investments. 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, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein.

Reserves Data (Forecast Prices and Costs)

SUMMARY OF CORPORATION OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2022
FORECAST PRICES AND COSTS

RESERVES CATEGORY	LIGHT AND MEDIUM CRUDE OIL Gross (Mbbl)	LIGHT AND MEDIUM CRUDE OIL Net (Mbbl)	HEAVY CRUDE OIL Gross (Mbbl)	HEAVY CRUDE OIL Net (Mbbl)	CONVENTIONAL NATURAL GAS Gross (MMcf)	CONVENTIONAL NATURAL GAS Net (MMcf)	NATURAL GAS LIQUIDS Gross (Mbbl)	NATURAL GAS LIQUIDS Net (Mbbl)	TOTAL Gross (MBOE)	TOTAL Net (MBOE)
Proved Developed										
Producing	3,770.1	3,298.2	3,286.0	3,009.7	10,915	9,992	553.2	481.0	9,428.4	8,454.2
Non-Producing	269.9	252.3	51.7	44.2	266	226	57.6	54.7	423.5	388.8
Proved Undeveloped	2,757.2	2,499.8	2,895.5	2,630.7	4,805	4,414	425.7	395.6	6,879.2	6,261.8
Total Proved	6,797.2	6,050.3	6,233.2	5,684.6	15,986	14,632	1,036.5	931.3	16,731.1	15,104.8
Probable	3,213.2	2,793.3	4,716.6	4,203.7	6,929	6,253	430.9	388.3	9,515.4	8,427.5
Total Proved plus Probable	10,010.3	8,843.6	10,949.8	9,888.3	22,915	20,884	1,467.3	1,319.7	26,246.5	23,532.3

NET PRESENT VALUES OF FUTURE NET REVENUE

RESERVES CATEGORY	BEFORE INCOME TAXES DISCOUNTED AT (%/year) 0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)	AFTER INCOME TAXES DISCOUNTED AT (%/year) 0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)	UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year ($/BOE)
Proved Developed											
Producing	202,323	214,518	198,276	180,555	165,307	202,323	214,518	198,276	180,555	165,307	23.45
Non-Producing	20,116	15,139	12,245	10,353	9,011	20,116	15,139	12,245	10,353	9,011	31.49
Proved Undeveloped	162,423	114,996	83,526	61,839	46,263	162,423	114,996	83,526	61,839	46,263	13.34
Total Proved	384,862	344,653	294,047	252,747	220,581	384,862	344,653	294,047	252,747	220,581	19.47
Probable	328,132	237,608	179,697	141,987	115,849	292,184	215,942	165,955	132,904	109,640	21.32
Total Proved plus Probable	712,994	582,261	473,744	394,734	336,430	677,046	560,595	460,002	385,651	330,221	20.13

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2022
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	DEVELOPMENT COSTS (M$)	ABANDONMENT AND RECLAMATION COSTS[1] (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)	INCOME TAXES (M$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)
Total Proved	1,281,201	133,098	466,779	163,455	133,006	384,862	0	384,862
Total Proved plus Probable	2,053,883	225,614	728,971	241,210	145,094	712,994	35,948	677,046

Note:

(1) Reflects estimated abandonment and reclamation for all existing wells (both active and inactive), undeveloped locations (booked by Sproule in the Sproule Report), and facilities. See "*Additional Information Relating to Reserves Data*".

FUTURE NET REVENUE
BY PRODUCT TYPE
AS OF DECEMBER 31, 2022
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCT TYPE	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M$)	UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year
Proved Reserves	Light and Medium Crude Oil[1]	179,398	$20.96/boe
	Heavy Crude Oil[1]	108,296	$18.31/boe
	Conventional Natural Gas[2]	6,353	$10.06/boe
	Other Items[4]	0	-
Proved Plus Probable Reserves	Light Crude Oil and Medium Crude Oil[1]	265,887	$21.34/boe
	Heavy Crude Oil[1]	200,528	$19.51/boe
	Conventional Natural Gas[2]	7,330	$9.25/boe
	Other Items[4]	-	-

Notes:
(1) Including solution gas and other by-products.
(2) Including by-products, but excluding solution gas and by-products from oil wells.
(3) Unit values are based on Net reserve volumes.
(4) Includes Alberta Capital Gas Cost Allowance and select scheduled Abandonment & Reclamation.

Notes to Reserves Data Tables:

1. Columns may not add due to rounding.

2. The crude oil, natural gas liquids and natural gas reserve estimates presented in the Sproule Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions is set forth in the "*Certain Definitions*" and below.

3. Levels of Certainty for Reported Reserves:

   The qualitative certainty levels referred to below are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserve estimates are prepared). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

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

(b) at least a 50% probability that the quantities actually recovered will equal or exceed the estimated proved plus probable reserves.

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

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

4. Forecast Costs and Price Assumptions

Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized by Sproule in the Sproule Report were an average of forecast prices and costs published by Sproule, GLJ Petroleum Consultants Ltd., and McDaniel & Associates Consultants Ltd. as at December 31, 2022, which are as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS

	OIL							
	WTI Cushing Oklahoma	Cdn Light Sweet Oil Price 40° API	WCS Oil Price	Natural Gas AB Plant Gate Spot Gas Price	Pentanes Plus Edmonton	Butanes Price Edmonton	Inflation Rates[1]	Exchange Rate[2]
Year	($US/bbl)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/MMBtu)	($Cdn/bbl)	($Cdn/bbl)	%/Year	($US/$Cdn)
Forecast								
2023	80.33	103.76	76.54	4.23	106.22	53.88	0.00	0.75
2024	78.50	97.74	77.75	4.40	101.35	52.67	2.33	0.77
2025	76.95	95.27	77.55	4.21	98.94	51.42	2.00	0.77
2026	77.61	95.58	80.07	4.27	100.19	51.61	2.00	0.77
2027	79.16	97.07	81.89	4.34	101.74	52.39	2.00	0.78
2028	80.74	99.01	84.02	4.43	103.78	53.44	2.00	0.78
2029	82.36	100.99	85.73	4.51	105.85	54.51	2.00	0.78
2030	84.00	103.01	87.44	4.60	107.97	55.60	2.00	0.78
2031	85.69	105.07	89.20	4.69	110.13	56.71	2.00	0.78
2032	87.40	106.69	91.11	4.79	112.33	57.56	2.00	0.78
2033+	Escalated oil, gas and product prices at 2% per year thereafter							

Notes:

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

Weighted average historical prices realized, before transportation and financial derivative contracts, by the Corporation for the year ended December 31, 2022 were $5.26/Mcf for natural gas, $120.24/bbl for light and medium oil, $98.94/bbl for heavy crude oil and $63.38/bbl for NGLs.

5. Sproule's evaluation reflects the full estimated abandonment and reclamation for all existing wells (both active and inactive), undeveloped locations (booked by Sproule in the Sproule Report), and facilities regardless of whether such entities had any attributed reserves.

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

7. The extent and character of all factual data supplied to Sproule were accepted by Sproule as represented. No field inspection was conducted.

8. The after-tax net present value of the Corporation's properties here reflects the tax burden on the properties on a stand-alone basis and utilizing the Corporation's tax pools. It does not consider the business-entity-level tax situation, or tax planning. It does not provide an estimate of the value at the level of the business entity, which may be significantly different. The financial statements and the management's discussion and analysis of the Corporation should be consulted for information at the level of the business entity. Furthermore, the tax methodology used assumes that all tax pools are utilized to the maximum depreciation rate as currently permitted.

Reconciliations of Changes in Gross Reserves

RECONCILIATION OF CORPORATION GROSS RESERVES BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM CRUDE OIL			HEAVY CRUDE OIL			NATURAL GAS LIQUIDS		
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)
December 31, 2021[1]	6,918.6	3,384.6	10,303.2	6,262.3	4,708.0	10,970.4	1,052.5	445.4	1,497.9
Discoveries	-	-	-	-	-	-	-	-	-
Extensions	324.9	56.2	381.2	497.7	389.2	886.9	20.7	5.4	26.1
Infill Drilling	30.3	(30.3)	-	-	-	-	0.8	(0.8)	-
Improved Recovery	264.0	160.2	424.2	151.3	319.0	470.3	33.2	(16.6)	16.6
Technical Revisions	(545.9)	(148.6)	(694.5)	(214.0)	(1,360.8)	(1,574.8)	(7.2)	1.2	(6.0)
Acquisitions	10.5	(9.8)	0.7	-	-	-	0.4	(0.3)	0.1
Dispositions	(5.7)	(2.3)	(8.1)	-	-	-	(1.0)	(0.4)	(1.4)
Economic Factors	473.0	(196.9)	276.1	543.4	661.1	1,204.4	37.9	(3.1)	34.8
Production	(672.5)	-	(672.5)	(1,007.4)	-	(1,007.4)	(100.9)	-	(100.9)
December 31, 2022[2]	6,797.2	3,213.2	10,010.3	6,233.2	4,716.6	10,949.8	1,036.5	430.9	1,467.3

FACTORS	CONVENTIONAL NATURAL GAS Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	TOTAL Gross Proved (MBOE)	Gross Probable (MBOE)	Gross Proved Plus Probable (MBOE)
December 31, 2021[(1)]	**14,506**	**6,818**	**21,324**	**16,651.0**	**9,674.3**	**26,325.3**
Discoveries	-	-	-	-	-	-
Extensions	885	339	1,223	990.8	507.3	1,498.1
Infill Drilling	27	(27)	-	35.6	(35.6)	-
Improved Recovery	509	90	599	533.3	477.7	1,011.0
Technical Revisions	796	(397)	399	(634.5)	(1,574.2)	(2,208.7)
Acquisitions	12	(10)	3	12.9	(11.7)	1.3
Dispositions	(12)	(5)	(17)	(8.6)	(3.6)	(12.2)
Economic Factors	1,136	121	1,257	1,243.6	481.2	1,724.8
Production	(1,873)	-	(1,873)	(2,093.0)	-	(2,093.0)
December 31, 2022[(2)]	**15,986**	**6,929**	**22,915**	**16,731.1**	**9,515.4**	**26,246.5**

Notes:

(1) The opening balance as at December 31, 2021 was derived from an independent engineering evaluation of Gear's oil, natural gas liquids and natural gas interests prepared by Sproule effective December 31, 2021 and dated February 7, 2022.
(2) Columns may not add due to rounding.

Both proved and proved plus probable reserves under economic factors were positively impacted by a stronger 2022 year end evaluator average price deck compared to the evaluator average price deck used for the opening balance.

The primary contributor to the negative technical revisions for the proved and proved plus probable reserves was increases in operating costs and carbon taxes impacting late life reserves, and increases in future development capital costs impacting marginally economic undeveloped locations across all of the Corporation's reserve areas. Base performance improvement in the Alberta West Minors area was offset by some base performance reductions in the Celtic area of Saskatchewan and the consolidation of several undeveloped locations in the Tableland area of Saskatchewan.

Additional Information Relating to Reserves Data

Undeveloped Reserves

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

Proved Undeveloped Reserves

Year	Light and Medium Crude Oil (Mbbl)		Heavy Crude Oil (Mbbl)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)		Oil Equivalent (MBOE)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2020	104.5	2,295.1	203.2	2,888.2	177	2,259	3.6	135.0	340.7	5,694.8
2021	57.2	3,172.1	476.2	2,902.2	280	5,230	2.0	533.2	582.1	7,479.1
2022	278.9	2,757.2	294.8	2,895.5	636	4,805	36.7	425.7	716.4	6,879.2

Notes:

(1) "First Attributed" refers to reserves first attributed at the year end of the corresponding fiscal year.
(2) Columns may not add due to rounding.

Probable Undeveloped Reserves

Year	Light and Medium Crude Oil (Mbbl)		Heavy Crude Oil (Mbbl)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)		Oil Equivalent (MBOE)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2020	80.1	3,252.8	134.7	3,524.6	(44)	3,043	(2.5)	138.7	205.0	7,423.3
2021	85.4	2,139.3	111.8	3,670.4	163	3,901	(6.2)	285.4	218.2	6,745.2
2022	39.5	1,682.8	592.1	3,719.0	501	3,477	(3.0)	231.2	712.0	6,212.4

Notes:

(1) "First Attributed" refers to reserves first attributed at the year end of the corresponding fiscal year.
(2) Columns may not add due to rounding.

In general, once proved and/or probable undeveloped reserves are identified, they are included in Gear's development plans. Both the proved and/or probable undeveloped reserves are fairly evenly distributed across the Corporations geographic and commodity play types.

The Corporation plans to develop 64% of its proved undeveloped reserves within two years, 93% within three years, and the remaining 7% of proved undeveloped reserves within five years. Beyond the reasons noted below, the Corporation plans to continue tight capital discipline in the short term until commodity pricing and other market factors provide greater economic certainty to accelerate development drilling. This drilling timeline provides strong cash flows to manage potential market uncertainties while still providing sufficient cash to accelerate its enhanced oil recovery opportunities, and meet other corporate objectives.

The Corporation plans to develop 62% of its probable undeveloped reserves within two years, 90% within three years, and the remaining 10% within five years. These locations will continue to be re-evaluated to assess their relative economic merits when compared to other projects available to the Corporation.

Undeveloped reserves planned to be developed beyond two to three years are scheduled in that manner due to various factors including access to capital, limitations on egress and pricing uncertainty. A number of factors that could result in delayed or cancelled development are as follows:

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

See "*Other Oil and Gas Information – Principal Properties*", "*Additional Information Relating to Reserves Data – Future Development Costs*" and "*Other Oil and Gas Information – Capital Expenditures*" for a description of the Corporation's exploration and development plans and expenditures.

Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting crude oil and natural gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present worth of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability and pricing of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and government restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

The Corporation does not anticipate any unusually high development costs or operating costs to produce and sell any material portion of its reserves. Where required, capital to construct facilities and pipelines necessary to deliver the forecasted products to market has been deducted from the estimates of cash flows used to calculate future net revenue. The Corporation has not entered into any contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized except for those contractual obligations described under the heading "*Other Oil and Gas Information – Forward Contracts and Marketing*".

The Corporation does not anticipate any unusually high abandonment or reclamation costs. Additional information related to our 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, pipelines and leases) can be found in Gear's audited financial statements for the year ended December 31, 2022 and the accompanying management's discussion and analysis, which are available on SEDAR at www.sedar.com.

Future Development Costs

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

	Forecast Capital Costs (M$)	
Year	Proved Reserves	Proved Plus Probable Reserves
2023	29,483	44,418
2024	62,970	89,612
2025	57,746	70,839
2026	13,257	27,012
2027	-	9,329
Thereafter	-	-
Total Undiscounted	163,455	241,210

On an ongoing basis, Gear will use internally generated funds from operations, debt and new equity issues if available on favourable terms to finance its capital expenditure program. The cost of funding is not expected to have any effect on disclosed reserves or future net revenue nor make the development of a property uneconomic for the Corporation.

If funds from operations are other than projected, capital expenditures may be adjusted. In addition, depending on a number of factors including commodity prices, industry conditions and the Corporation's financial and operating results, debt or equity financing may not be available, which could also result in adjustments to the capital program as required.

Other Oil and Gas Information

Principal Properties

The Corporation is engaged in the exploration for and development and production of crude oil and natural gas in Western Canada. All of the Corporation's current operations are in the Provinces of Alberta and Saskatchewan, with some minor operations in the Province of British Columbia.

The following is a description of the Corporation's oil and natural gas properties as at the date hereof, unless otherwise stated. The reserve amounts stated are Gross reserves, as at December 31, 2022 based on forecast costs and prices as evaluated in the Sproule Report (see "*Reserves Data*"). The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation. The production values are all stated on a company interest basis, which includes Gear's royalty interests but does not deduct for royalties payable by Gear.

Celtic/Paradise Hill, Saskatchewan

The Celtic/Paradise Hill property was acquired as primarily undeveloped non-producing land starting in March 2014 and is located within Township 52, and Ranges 23 and 24 W3 and is approximately 40 kilometres northeast of Lloydminster Alberta. It is currently comprised of approximately 4,500 Gross (4,500 Net) acres of land. There are no material expiries expected as the majority of lands have been continued pursuant to the applicable tenure regulations.

Celtic/Paradise Hill is characterized by unconsolidated Upper Mannville group clastic reservoirs with depths ranging from 500 meters to 650 meters. While the McLaren formation has been the most exploited interval, Sparky and Waseca also hold potential as future development targets on Gear acreage.

Consistent with Gear's other heavy crude oil sites, each one to four well pad is equipped to operate independently and as such, the risk of a single event culminating into a material production loss is mitigated. Solution gas is gathered through a pipeline system and is used to provide fuel gas to operate on-lease equipment and heat production tanks. All oil production is tank treated to produce sales quality oil before being trucked to sales points.

In 2014 Gear successfully drilled the first two Gross (2 Net) half section lined horizontal McLaren oil wells into the area. In 2015, a further three Gross (3 Net) horizontal wells were drilled. In 2016, Gear drilled an additional eight Gross (8 Net) horizontal McLaren oil wells. In 2017, Gear drilled fifteen Gross (15 Net) horizontal McLaren oil wells. In 2018, Gear drilled ten Gross (10 Net) horizontal McLaren oil wells. In 2019, Gear did not drill any wells in the area. In 2020, Gear drilled seven Gross (7 Net) horizontal McLaren oil wells in the area. In 2021, Gear drilled 10 Gross (10 Net) horizontal McLaren oil wells in the area. In 2022, Gear drilled One Gross (1 Net) horizontal McLaren oil well in the Celtic/Paradise Hill area. The plan for 2023 has no budgeted drilling in the area. See "*Description of the Business – Business Plan and Corporate Strategy*".

The Sproule Report assigns total proved plus probable reserves of 3,376.9 Mbbls of heavy crude oil at December 31, 2022 within the Celtic area. The average production from the area for in 2022 was 1,178 BOE/d all of which consisted of heavy crude oil.

Wildmere Area, Alberta

The Wildmere field is located within Townships 47, 48 and 49, and Ranges 3, 4, 5 and 6W4, is approximately 200 kilometres southeast of Edmonton, Alberta. The property consists of approximately 24,325 Gross (23,000 Net) acres of lands with no material expiries as the majority of lands have been continued pursuant to the applicable tenure regulations.

The Wildmere area is a heavy crude oil area characterized by unconsolidated Mannville group clastic reservoirs with depths ranging from 600 meters to 700 meters. While the General Petroleum, Lloydminster and Cummings formations have been the most exploited intervals, the Colony and Sparky formations have also proven to be successful development targets for heavy crude oil on Gear acreage.

Each of Gear's Wildmere heavy crude oil sites is the surface location for one to four wells. Every pad is equipped to operate independently and, as such, the risk of a single event resulting in a material production loss is mitigated. Solution gas is pipeline connected through most of the field allowing wells to share gas for tank heating, to sell gas, or to deliver purchased gas if desired in order to offset propane otherwise used for tank heating. All Wildmere oil production is tank treated to produce sales quality oil before being trucked to sales points.

In 2016, Gear drilled three Gross (3 Net) quad-lateral un-lined horizontal wells in the Cummings at Wildmere. The original 2016 budget included plans to drill eleven multi-lateral horizontal Wildmere wells into the Cummings formation; however, that plan was put on hold due to poor oil prices. In 2017, Gear drilled five Gross (5 Net) multi-lateral un-lined horizontal wells in the Cummings at Wildmere. During 2017, six Gross (6 Net) dual-lateral un-lined horizontal wells targeting the General Petroleum formation were also drilled in Wildmere. In 2018, Gear drilled five Gross (5 Net) multi-lateral un-lined horizontal heavy crude oil wells in the Cummings and the Sparky formations. In 2019, Gear drilled eight Gross (8 Net) multilateral un-lined horizontal heavy crude oil wells in the General Petroleum and Sparky formations. In 2020, Gear did not drill any wells in the area. In 2021, Gear drilled three Gross (3 Net) multilateral un-lined horizontal heavy crude oil wells in the General Petroleum and Sparky formations, and initiated waterflood activities in the General Petroleum formation. In 2022, Gear drilled five Gross (5 Net) multilateral un-lined horizontal heavy crude oil wells in the General Petroleum and Sparky formations. The plan for 2023 includes drilling up to six Gross (6 Net) General Petroleum, one Gross (1 Net) Sparky, and one Gross (1 Net) Cummings budgeted multi-lateral heavy crude horizontal oil wells, and initiating and expanding waterflood activity in two pools. See "*Description of the Business – Business Plan and Corporate Strategy*".

The Sproule Report assigns total proved plus probable reserves of 4,379.0 Mbbls of heavy crude oil and 1.58 Bcf of natural gas as at December 31, 2022 within the Wildmere area. The average production from the area in 2022 was 1,097 BOE/d, which consisted of 1,036 bbls/d of heavy crude oil and 371 mcf/d of conventional natural gas.

Wilson Creek, Alberta

The Wilson Creek property was acquired in July 2016 pursuant to the Striker Arrangement and is located primarily within Townships 42 and 43, and Ranges 4 and 5 W5 in Central Alberta. The primary target zone is the regional Basal Belly River consolidated sandstone formation, which is a light oil pool that requires hydraulic fracturing. It is comprised of approximately 48,600 Gross (40,000 Net) acres of land. There are no material expiries expected as the majority of lands have been continued pursuant to the applicable tenure regulations.

Wilson Creek development is primarily characterized by the Basal Belly River reservoir with depth of approximately 1,300 meters. The light oil in the area is processed partially at single well batteries and partially with individual wells flow-lined to central facilities. In both cases, the resulting clean oil is trucked to the various sales points. The associated gas from Wilson Creek is gathered through third party infrastructure and sold to various parties.

In 2016 following completion of the Striker Arrangement, Gear drilled 2 Gross wells (2 Net) full section horizontal light oil wells into the Basal Belly River, one of which was completed in late 2016 and the other which was completed in early 2017. In 2017, Gear drilled three Gross wells (2.8 Net) full section horizontal light oil wells into the Basal Belly River. In 2018, Gear drilled seven Gross (4.9 Net) full section or extended reach light oil horizontal wells and initiated waterfloods. In 2019, Gear drilled one Gross (1 Net) horizontal light oil well in the Wilson Creek area and expanded waterflood activity. In 2020, Gear did not drill any wells in the area, but did convert an additional well to injection for further waterflood optimization. In 2021, Gear participated in two Gross (0.7 Net) non-operated extended reach light oil wells, and expanded waterflood activity in two pools. In 2022, there was no drilling or expanded waterflood activity in the Wilson Creek area. The plan for 2023 includes drilling one Gross (1 Net) Belly River horizontal light oil well, and expanding waterflood activity in one pool with the addition of one Gross (1 Net) source water horizontal well. See "*Description of the Business – Business Plan and Corporate Strategy*".

The Sproule Report assigns total proved plus probable reserves of 3,396.1 Mbbls of light crude oil and NGLs and 6.41 Bcf of natural gas as at December 31, 2022 within Wilson Creek. The average production from the area in 2022 was 803 BOE/d, which consisted of 445 bbls/d of light and medium crude oil, 1,283 mcf/d of conventional natural gas and 144 bbls/d of natural gas liquids.

Tableland, Saskatchewan

The Tableland property was acquired in September 2018 pursuant to the Steppe Arrangement and is located primarily within Townships 1 and 2, and Ranges 10 and 11 W2, approximately 30 kilometers southwest of Estevan in Southeast Saskatchewan.

It is comprised of approximately 25,000 Gross (24,600 Net) acres of land. There are no material expiries expected as the majority of lands have been continued pursuant to the applicable tenure regulations.

Tableland development is predominately focused on the Three Forks/Torquay formation, with minor production from the Bakken and Ratcliffe formations. The reservoir depths range from 1,800 to 2,100 meters. The sweet, light oil in the area is transported via pipe and truck to be processed at two Gear-owned central facilities. Sales oil is then trucked from those facilities to various sales points. Most of the associated gas from the Tableland production is now conserved through a third party mid-streamer. Small gas volumes associated with single well batteries and low volume facilities are still being flared, although various options for conservation continue to be evaluated.

The acquisition of the Tableland property provides Gear with an opportunity to utilize its fractured drilling expertise developed in Wilson Creek, Alberta in the Torquay formation. The Tableland acquisition also provides Gear with an opportunity to potentially exploit the Ratcliffe and Bakken formations using multi-lateral, un-lined horizontal drilling techniques, similar to those employed successfully by the Corporation throughout its heavy crude oil portfolio. In 2019, Gear drilled five Gross (5 Net) two mile horizontal light oil wells in the Tableland area. In 2020, Gear did not drill any wells in the area. In 2021, Gear drilled one Gross (1.0 Net) light crude Torquay two mile horizontal oil well in the area. In 2021, Gear also engaged a private midstream company under a multi-year deal to collect and process gas and natural liquid gas volumes from its 03-16-01-11W2 battery that would otherwise have been flared. This arrangement eliminated Gear's largest single point gas flare. In 2022, Gear drilled three Gross (3 Net) two mile horizontal light oil wells in the area and initiated waterflood activity in one pool. The plan for 2023 is to drill one Gross (1 Net) light crude Torquay two mile horizontal oil well in the area, and expand the 2022 waterflood project. See "*Description of the Business – Business Plan and Corporate Strategy*".

A pipeline owned by Gear runs from the Tableland property in Saskatchewan to Divide County, North Dakota. Although the pipeline was initially built by Steppe to transport natural gas from Tableland to the United States for the sale of such natural gas, no substances have been transported through the pipeline since February 1, 2016.

The Sproule Report assigns total proved plus probable reserves of 4,663.2 Mbbls of light crude oil and NGLs and 3.01 BCF of natural gas as at December 31, 2022 within Tableland. The average production from the area in 2022 was 771 BOE/d, which consisted of 605 bbls/d of light and medium crude oil, 433 mcf/d of conventional natural gas and 93 bbls/d of natural gas liquids.

Other Areas

The Corporation held interests in a number of wells and lands in other portions of Alberta, British Columbia and Saskatchewan at December 31, 2021. In 2017, Gear drilled three Gross (3 Net) heavy crude oil wells in Hoosier, Saskatchewan, and two Gross (2 Net) medium oil wells in Killam, Alberta. In 2018, Gear drilled two Gross (2 Net) heavy crude oil wells in Hoosier, Saskatchewan, one Gross (1 Net) heavy crude oil well in Lindbergh, Alberta and one Gross (1 Net) heavy crude oil well in Maidstone, Saskatchewan. In 2019, Gear drilled two Gross (2 Net) wells in the Maidstone area. In 2020, Gear drilled two Gross (2 Net) multilateral un-lined horizontal heavy crude oil wells in the Lindbergh area, one Gross (1 Net) multilateral un-lined horizontal medium crude oil well in the Provost area and one Gross (1 Net) horizontal medium oil well in the Killam area, and continued expansion of the waterflood in Killam. In 2021, Gear drilled four Gross (4 Net) multi-lateral medium crude horizontal oil wells in the Provost area. In 2022, Gear drilled three Gross (3 Net) multilateral un-lined horizontal heavy crude oil wells in the Lindbergh area, one Gross (1 Net) multilateral un-lined horizontal heavy crude oil well in the Maidstone area, six Gross (6 Net) multi-lateral medium crude horizontal oil wells in the Provost area, four Gross (4 Net) horizontal medium oil wells in the Killam area, one Gross (1 Net) horizontal Belly River source water well in the Killam area, and continued expansion of the waterfloods in Killam and Maidstone areas. The plan for 2023 includes drilling up two Gross (2 Net) lined horizontal heavy crude oil wells in the Hoosier area, two Gross (2 Net) multi-lateral unlined heavy crude horizontal oil wells in the Lindbergh area, three Gross (3 Net) multi-lateral unlined heavy crude horizontal wells in the Maidstone area, two Gross (2 Net) multi-lateral medium crude horizontal oil wells in the Provost area, three Gross (3 Net) horizontal medium oil wells in the Killam area, and continued expansion of the waterflood in Killam while initiating waterflooding in Provost. See "*Description of the Business – Business Plan and Corporate Strategy*".

The Sproule Report assigns total proved plus probable reserves of 6,612.2 Mbbls of light, medium and heavy crude oil and NGLs and 11.92 Bcf of natural gas as at December 31, 2022 within these other areas. The average production from these areas in 2022 was 1,890 BOE/d, which consisted of 795 bbls/d of light and medium crude oil, 544 bbls/d of heavy crude oil 3,036 mcf/d of conventional natural gas and 45 bbls/d of natural gas liquids.

Oil and Gas Wells

The following table sets forth the number and status of crude oil and natural gas wells (all of which are onshore) in which the Corporation had a working interest as at December 31, 2022.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	301	247	487	431	462	110	134	93
British Columbia	-	-	-	-	-	-	4	-
Saskatchewan	141	140	159	144	5	5	23	21
Total	442	387	646	575	467	115	161	114

Note:

(1) This table does not include water source wells, injection wells, abandoned wells or wells which have never produced. Producing wells are based on public data status.

Land Holdings Including Properties with no Attributable Reserves

The following table sets out the Corporation's developed and undeveloped land holdings as at December 31, 2022.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	131,889	106,652	69,103	62,040	200,991	168,692
British Columbia	4,010	3,663	3,373	3,026	7,384	6,689
Saskatchewan	36,862	33,131	23,831	23,569	60,693	56,700
Total	172,760	143,446	96,307	88,635	269,068	232,081

Gear calculates both its Gross and Net acres on a per lease basis. Undeveloped lands are calculated by adding the surface area acreage covered by the leases or agreements or portions of the leases or agreements without producing or potentially producing wells. In certain limited circumstances where the Corporation has rights in different formations under the same surface area pursuant to different leases or agreements, we have included the acreage with respect to all such leases or agreements. There are no significant factors or uncertainties associated with the undeveloped land.

Gear has approximately 9,000 net acres of its undeveloped land holdings that may expire by December 31, 2023, a portion of which may be continued pursuant to applicable tenure regulations. Gear plans to drill or submit application to continue selected portions of the above acreage.

Forward Contracts and Marketing

Most of Gear's crude oil and natural gas production is sold to major marketers on prearranged terms with indexing to published spot pricing. In a typical month, Gear splits the sale of its crude oil between several purchasers. These crude oil purchasers then ship Gear's crude oil via both pipeline and rail as title transfers at either pipeline or railway terminals. Gear does not set targets on the amount of crude oil to be sold into railway terminals; rather, it directs its oil sales to the highest received price net of transportation. Gear's established method of mitigating counter party risk is to deal with counterparties with strong credit ratings and to accept pre-payment on oil deliveries from smaller purchasers or those with less established credit ratings, if applicable.

The contract term is generally a 30-day evergreen in the case of pipeline connected crude oil buyers and up to one year for natural gas and natural gas liquids. For crude oil purchaser contracts at rail terminals, Gear generally enters into volume-based purchase contracts with 1 to 12 month terms. None of Gear's purchase agreements currently contain material non-performance penalties.

Gear may periodically hedge the price of a portion of its crude oil and natural gas production. The Corporation has no firm gas transportation contracts.

A summary of contracts outstanding, as at December 31, 2022, in respect of the hedging activities is included in Note 10 to Gear's audited financial statements for the year ended December 31, 2022, which are available on SEDAR at www.sedar.com.

Tax Horizon

Based on current forward commodity prices, the Corporation does not expect to pay current income tax for the 2023 fiscal year. Gear may pay income taxes in the next 5 years depending on multiple factors which impact the tax horizon of the Corporation, the most notable being production, commodity prices and capital spending levels. Gear currently recognizes a deferred tax asset as current tax pools and other temporary differences exceed the book value of property, plant and equipment.

Capital Expenditures

The following table summarizes capital expenditures related to the Corporation's activities for the year ended December 31, 2022:

	(M$)
Corporate Acquisition Cost	-
Property Acquisition Costs	
Proved properties	-
Undeveloped properties	-
Exploration costs	1,177
Development costs	49,372
Dispositions	-
Total	50,549

Exploration and Development Activities

The following table sets forth the Gross and Net exploratory and development wells in which the Corporation participated during the year ended December 31, 2022:

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Light and Medium Crude Oil	-	-	13.0	13.0
Heavy Crude Oil	-	-	10.0	10.0
Conventional Natural Gas	-	-	-	-
Dry	-	-	-	-
Service/Other	-	-	1.0	1.0
Stratigraphic Test	-	-	-	-
Total	-	-	24.0	24.0

See "*Statement of Reserves Data and Other Oil and Gas Information – Principal Properties*" for a description of the

Corporation's exploration and development plans.

Production Estimates

The following tables disclose, by product type, and by area, the total volume of the Corporation's Gross production estimated by Sproule for 2023 in the estimates of future net revenue from Gross proved and Gross probable reserves disclosed under "*Disclosure of Reserves Data*".

From Gross Proved Reserves:	Light and Medium Crude Oil (bbls/d)	Heavy Crude Oil (bbls/d)	Conventional Natural Gas (Mcf/d)	Natural Gas Liquids (bbls/d)	BOE (BOE/d)	%
Wildmere	-	1,111	502	-	1,195	20
Celtic	-	839	-	-	839	14
Wilson Creek	472	-	1,353	130	828	14
Tableland	741	-	606	135	977	16
Other	873	737	3,315	42	2,203	36
Total	2,086	2,687	5,776	307	6,042	100

Note:

(1) Columns may not add due to rounding.

From Gross Probable Reserves:	Light and Medium Crude Oil (bbls/d)	Heavy Crude Oil (bbls/d)	Conventional Natural Gas (Mcf/d)	Natural Gas Liquids (bbls/d)	BOE (BOE/d)	%
Wildmere	-	301	146	-	325	39
Celtic	-	52	-	-	52	6
Wilson Creek	45	-	92	9	69	8
Tableland	95	-	58	13	118	14
Other	110	118	268	3	276	33
Total	250	471	564	25	840	100

Note:

(1) Columns may not add due to rounding.

Production History

The following tables summarize certain information in respect of production (which includes royalty interest volumes), product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below:

	2022			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production[(1)]				

	2022			
	Dec. 31	Sept. 30	June 30	Mar. 31
Light and Medium Crude Oil (bbls/d)[2]	1,835	1,971	1,980	1,580
Heavy Crude Oil (bbls/d) [2]	2,772	2,546	2,686	3,043
Conventional Natural Gas (Mcf/d) [3]	5,091	5,339	5,205	4,855
NGLs (bbls/d)	299	320	243	269
Combined (BOE/d)	5,755	5,727	5,777	5,701
Average Price Received				
Light and Medium Crude Oil ($/bbl)[2]	103.62	109.95	133.18	110.32
Heavy Crude Oil ($/bbl) [2]	69.72	89.32	116.74	95.91
Conventional Natural Gas ($/Mcf) [3]	5.11	4.47	7.38	4.64
NGLs ($/bbl)	58.48	60.62	72.59	63.88
Combined ($/BOE)	74.19	85.10	109.63	88.73
Royalties Paid				
Light and Medium Crude Oil ($/bbl)[2]	10.77	12.41	13.70	11.28
Heavy Crude Oil ($/bbl) [2]	13.06	16.40	20.27	10.86
Conventional Natural Gas ($/Mcf) [3]	0.36	0.27	0.91	0.21
NGLs ($/bbl)	6.69	5.84	14.92	6.07
Combined ($/BOE)	10.40	12.14	15.56	9.38
Operating Expenses ($/BOE)				
Light and Medium Crude Oil ($/bbl)[2]	26.72	26.25	27.68	25.42
Heavy Crude Oil ($/bbl) [2]	27.80	26.75	26.73	23.89
Conventional Natural Gas ($/Mcf) [3]	3.60	3.60	3.41	3.45
NGLs ($/bbl)	9.34	9.76	10.14	10.67
Combined ($/BOE)	25.58	24.83	25.42	23.23
Netback Received ($/BOE)[4]				
Light and Medium Crude Oil ($/bbl)[2]	66.13	71.30	91.80	73.62
Heavy Crude Oil ($/bbl) [2]	28.85	46.17	69.75	61.16
Conventional Natural Gas ($/Mcf) [3]	1.15	0.60	3.07	0.99
NGLs ($/bbl)	42.46	45.01	47.53	47.13
Combined ($/BOE)	38.21	48.13	68.65	56.12

Notes:

(1) Before deduction of royalties.
(2) Including solution gas and other by-products.
(3) Including by-products, but excluding solution gas and by-products from oil wells. Includes immaterial volumes of production from coal bed methane reserves.
(4) Netbacks are calculated by subtracting royalties, and operating and transportation costs from revenues.

The following table indicates the Corporation's average daily production from its important areas for the year ended December 31, 2022:

	Light and Medium Crude Oil[1] (bbls/d)	Heavy Crude Oil[1] (bbls/d)	Conventional Natural Gas[2] (Mcf/d)	NGLs (bbls/d)	BOE (BOE/d)
Celtic	-	1,178	-	-	1,178
Wildmere	-	1,036	371	-	1,097
Wilson Creek	445	-	1,283	144	803
Tableland	605	-	433	93	771
Other	795	544	3,036	45	1,890
Total	1,845	2,758	5,124	283	5,740

Notes:

(1) Including solution gas and other by-products.
(2) Including by-products, but excluding solution gas and by-products from oil wells.

The Corporation's production for the year ended December 31, 2022 was 48% heavy crude oil, 32% light and medium oil, 15% natural gas and 5% was NGLs. For the year ended December 31, 2022, approximately 95% of the Corporation's gross revenue was derived from crude oil and NGLs production and 5% was derived from natural gas production.

DIVIDEND POLICY

In 2022, the Board implemented a dividend program initially based on a variable quarterly dividend which was updated to a regular monthly cash dividend. If declared, the monthly dividend is expected to be paid on or about the last day of each month to holders of record of Common Shares on or about the 15th day of such month.

It is intended that dividends declared and paid by Gear will qualify as "eligible dividends" for the purposes of the *Income Tax Act* (Canada) (and any similar applicable provincial legislation). No assurances can be given that all dividends will qualify as "eligible dividends" and the designation of dividends as "eligible dividends" will be subject to the discretion of the Board.

Notwithstanding the foregoing, the decision to declare any dividend and the amount of future cash dividends declared and paid by Gear, if any, will be subject to the discretion of the Board and may vary depending on a variety of factors and conditions existing from time to time, including, without limitation, fluctuations in commodity prices, business performance, operating environment where Gears' assets are located, financial condition, growth plans, production levels, expected capital expenditure requirements, operating costs, royalty burdens, foreign exchange rates, interest rates, compliance with any restrictions on the declaration and payment of dividends contained in any agreements to which Gear or any of its subsidiaries is a party from time to time (including, without limitation, the agreements governing the Credit Facilities), and the satisfaction of liquidity and solvency tests imposed by the *Business Corporations Act* (Alberta) for the declaration and payment of dividends. The actual amount, the record date and the payment date of any dividend are subject to the discretion of the Board. There can be no assurance that dividends will be paid at the current rate or at any rate in the future.

The Board intends to review the dividend program from time to time, at its discretion. Depending on the foregoing factors and any other factors that the Board deems relevant from time to time, many of which are beyond the control of the Corporation, the Board may change the program following any such review or at any other time that the Board deems appropriate. Any such change may include, without restriction, future cash dividends being reduced or suspended entirely.

The Corporation did not pay any dividends in the years ended December 31, 2021 and 2020. During the year-ended December 31, 2022, the Corporation paid the following monthly cash dividends:

2022	**($ per share Cdn)**
January	$-
February	$-
March	$-
April	$-
May	$0.01
June	$-
July	$-
August	$0.02
September	$0.01
October	$0.01
November	$0.01
December	$0.01
Total 2022	**$0.07**

In addition to the foregoing, the Corporation's ability to pay dividends now or in the future may be limited by covenants contained in the agreements governing any indebtedness that the Corporation has incurred or may incur in the future including the terms of the Credit Facilities. The Credit Facilities prohibits the Corporation from declaring or paying any dividends to any of its shareholders if: (i) declaring or paying the dividend would result in a default under the Credit Facilities; or (ii) if the Corporation is drawn greater than 50 per cent of the borrowing base of the Credit Facilities.

DESCRIPTION OF CAPITAL STRUCTURE

The Corporation is authorized to issue an unlimited number of Common Shares, an unlimited number of Preferred Shares, issuable in series, and an unlimited number of Series 1 Preferred Shares, of which 261,210,007 Common Shares and no Series 1 Preferred Shares are currently issued and outstanding. The following is a summary description of the rights, privileges, restrictions and conditions attaching to the Common Shares, the Preferred Shares and the Series 1 Preferred Shares.

Common Shares

The Corporation has an unlimited number of Common Shares authorized. The holders of Common Shares are entitled to: dividends if, as and when declared by the Board; to vote at any meetings of the holders of Common Shares; and upon liquidation, dissolution or winding up of the Corporation, receive the remaining property and assets of the Corporation. All of the Common Shares outstanding are fully paid and non-assessable.

Preferred Shares

Gear is authorized to issue an unlimited number of Preferred Shares issuable in series, each series consisting of such number of shares and having such rights, privileges, restrictions and conditions as may be determined by the Board prior to the issuance thereof. With respect to the payment of dividends and the distribution of assets in the event of liquidation, dissolution or winding up of Gear, whether voluntary or involuntary, the Preferred Shares are entitled to preference over the Common Shares and any other shares ranking junior to the Preferred Shares from time to time and may also be given such other preferences over the Common Shares and any other shares ranking junior to the Preferred Shares as may be determined at the time of creation of such series.

Series 1 Preferred Shares

At the date hereof, Gear has created Series 1 Preferred Shares; however, no Series 1 Preferred Shares are outstanding. The holders of Series 1 Preferred Shares are not entitled to receive notice of, attend nor vote at any meetings of the shareholders of the Corporation. Subject to the provisions of any other series of Preferred Shares created after the date of the creation of the Series 1 Preferred Shares, the holders of Series 1 Preferred Shares are entitled to receive, if, as and when declared by the Board, any dividends declared by the Board. Any dividends declared and paid on the Common Shares must also be declared and paid on the Series 1 Preferred Shares, which shall be in priority to the holders of the Common Shares. In the event of liquidation, dissolution or winding-up of the Corporation or any other distribution of assets of the Corporation among its shareholders for the purposes of winding up the affairs of the Corporation, the Series 1 Preferred Shares shall rank in priority to the Common Shares in a sum equivalent to the value of the Series 1 Preferred Shares; provided that the amount to be received by the Series 1 Preferred Shares will be equivalent to the amount to be received per Common Share upon such liquidation, dissolution or winding up and subject to the provisions of any other series of Preferred Shares created after the date of the creation of the Series 1 Preferred Shares.

MARKET FOR SECURITIES

Trading Price and Volume

The Common Shares are listed and posted for trading on the TSX under the symbol "GXE". The following table sets forth the high and low sales prices (which are not necessarily the closing prices) and the trading volumes for the Common Shares on the TSX as reported by the TSX for the periods indicated since the beginning of the year ended December 31, 2022:

	Price Range ($)		Trading
Period	**High**	**Low**	**Volume**
2022			
January	1.40	0.90	47,831,902
February	1.67	1.36	59,417,953
March	1.94	1.39	58,457,712
April	1.68	1.35	43,609,322
May	1.73	1.36	55,514,689

Period	Price Range ($) High	Low	Trading Volume
June	1.67	1.16	54,100,244
July	1.38	0.98	32,220,011
August	1.40	1.17	29,637,347
September	1.35	1.02	28,994,740
October	1.40	1.16	23,569,714
November	1.45	1.15	39,808,651
December	1.20	0.99	29,184,821
2023			
January	1.17	1.03	30,626,637
February	1.16	1.01	26,816,783
March (1 -23)	1.14	0.90	36,064,567

Prior Sales

The following table sets forth the securities of the Corporation issued during the year ended December 31, 2022 that are not listed on the TSX (or any other stock exchange):

Date	Number of Securities	Issue Price Per Security(1) ($)	Type of Security
February 28, 2022	723,000	1.50	Options
May 16, 2022	2,832,000	1.43	Options
August 9, 2022	696,000	1.26	Options
November 14, 2022	4,308,000	1.34	Options

Note:

(1) Represents the exercise price of Options.

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

To the knowledge of management of the Corporation, none of the securities of the Corporation are held in escrow or are subject to a contractual restriction on transfer as at the date hereof.

DIRECTORS AND EXECUTIVE OFFICERS

Name, Occupation and Security Holding

The following table sets forth certain information in respect to Gear's directors and executive officers:

Name, Province and Country of Residence	Position(s) with Gear	Principal Occupation During the Five Years Preceding
Greg Bay(1)(3) British Columbia, Canada	Director since August 2019 (previously a director from 2013 to 2016)	Founding Partner and Managing Partner of Cypress Capital Management Ltd., an investment management firm, since 1998.
Harry English(1)(3) Alberta, Canada	Director since June 2014	Corporate director and independent businessman since June 2014. Prior thereto, partner at Deloitte LLP, Calgary since 2002.
Ingram Gillmore Alberta, Canada	President, Chief Executive Officer since May 2010 and a Director since June 2010	President and Chief Executive Officer of the Corporation since May 2010; prior thereto Vice President, Engineering at ARC Resources Ltd. ("**ARC**")

Name, Province and Country of Residence	Position(s) with Gear	Principal Occupation During the Five Years Preceding
Don T. Gray[(1)(2)(3)] Arizona, United States of America	Chairman since January 2010 and a Director since February 2009	Private investor; a director of the Corporation since February 2009 and Chairman of the Corporation since January 2010; Chairman of the Board of Petrus Resources Ltd., a public oil and gas company, since 2010; prior thereto, Mr. Gray was the Chief Executive Officer of Peyto Exploration & Development Corp. (formerly Peyto Energy Trust) ("**Peyto**") from August 2006 to January 2007; prior thereto, Mr. Gray was the President and Chief Executive Officer of Peyto from October 1998 to August 2006.
Scott Robinson[(2)(3)] Alberta, Canada	Director since July 2019	Vice President, Business Development of Peyto, a public oil and gas company, since November 2019; prior thereto, Executive Vice President Operations and Chief Operating Officer of Peyto from 2006 to February 2019.
Wilson Wang[(1)(3)] Hawaii, United States of America	Director since August 2019	Managing Partner and founder of Twin Peaks Capital LLC, an investment management firm, since 2014, and founder of HFI Research, a research firm focused on the oil and gas industry since 2015.
Bindu Wyma[(2)(3)] Alberta, Canada	Director since June 2018	An independent businesswoman; Vice President of Business Development for North America of Talisman Energy Inc. from 2011 to 2015. Prior thereto, Ms. Wyma held various positions at Talisman since 1997.
Bryan Dozzi Alberta, Canada	Vice President, Engineering since June 2015	Vice President, Engineering since June 2015; prior thereto Engineering Manager of the Corporation from April 2014 to June 2015 and Vice President, Business Development at Rock Energy Inc. from December 2010 to December 2012.
David Hwang Alberta, Canada	Vice President, Finance and Chief Financial Officer since June 2011	Vice President, Finance of Gear since June 2011; prior thereto, controller at ARC since 2010 and, prior thereto, manager at ARC since 2006.
Jason Kaluski Alberta, Canada	Vice President, Operations since March 2011	Vice President, Operations of Gear since March 2011; prior thereto, manager of operations for Questerre Energy Corporation from 2008 to 2011.
Dustin Ressler Alberta, Canada	Vice President, Exploration since November 2016	Vice President, Exploration since November 2016; prior thereto, Geology Manager with the Corporation from April 2014 to October 2016 and geologist at Gear from October 2010 to April 2014.
Edward (Ted) Brown Alberta, Canada	Corporate Secretary since August 2015	Partner and Co-Leader of the Business Law Group at the Calgary based law firm of Burnet, Duckworth & Palmer LLP and has practiced corporate and securities law since 2005.

Notes:

(1) Member of the Audit Committee.
(2) Member of the Reserves Committee.
(3) Member of the Corporate Governance, Compensation and Sustainability Committee.
(4) Gear does not have an Executive Committee.
(5) Gear's directors will hold office until the next annual general meeting of the Corporation's shareholders or until each director's successor is appointed or elected pursuant to the ABCA.

As at the date of this Annual Information Form, the number of Common Shares beneficially owned, or controlled or directed, directly or indirectly, by all of the directors and officers of Gear is 20,416,229 Common Shares constituting approximately 7.82% of the issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Cease Trade Orders

To the knowledge of Gear, no director or executive officer of Gear (nor any personal holding company of any of such persons) is, as of the date of this Annual Information Form, or was within ten years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company (including Gear), that: (a) was subject to a cease trade order (including a management 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, in each case that was in effect for a period of more than 30 consecutive days (collectively, an "**Order**"), that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (b) was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

Bankruptcies

To the knowledge of Gear, no director or executive officer of Gear (nor any personal holding company of any of such persons) or shareholder holding a sufficient number of securities of Gear to affect materially the control of Gear: (a) is, as of the date of this Annual Information Form, or has been within the ten years before the date of this Annual Information Form, a director or executive officer of any company (including Gear) 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, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (b) has, within the ten years before the date of this Annual Information Form, 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 Gear, no director or executive officer of Gear (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of securities of Gear to affect materially the control of Gear, has been subject to: (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

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

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal Proceedings

None of the Corporation or any of its subsidiaries is a party to any legal proceeding nor was it a party to any legal proceeding during the financial year ended December 31, 2022, nor is the Corporation aware of any contemplated legal proceeding involving the Corporation or its subsidiaries or any of its property which involves a claim for damages exclusive of interest and costs that may exceed 10% of the current assets of the Corporation.

Regulatory Actions

During the year ended December 31, 2022, there were no (i) penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority; (ii) any other penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision, or (iii) settlement agreements the Corporation entered into before a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

The Corporation is not aware of any material interests, direct or indirect, of any director or executive officer of the Corporation, any person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of any class or series of the Corporation's outstanding voting securities, or any associate or affiliate of any of the foregoing persons or companies, in any transaction within the three most recently completed financial years or during the current financial year which has materially affected or is reasonably expected to materially affect the Corporation, other than as disclosed elsewhere in this Annual Information Form.

TRANSFER AGENT AND REGISTRAR

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

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business (unless otherwise required by applicable securities requirements to be disclosed), the Corporation has not entered into any material contracts during the last financial year, or before the last financial year which are still in effect.

INTERESTS OF EXPERTS

Names of Experts

The only persons or companies who are named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under NI 51-102 by the Corporation during, or relating to, the Corporation's most recently completed financial year, and whose profession or business gives authority to the report, valuation statement or opinion made by the person or company, are Deloitte LLP, the Corporation's independent auditors, and Sproule, the Corporation's independent engineering evaluators.

Interests of Experts

To the Corporation's knowledge, there were no registered or beneficial interests, direct or indirect, in any securities or other property of the Corporation or of one of its associates or affiliates: (i) held by Sproule or by the "designated professionals" (as defined in Form 51-102F2 to NI 51-102) of Sproule, when Sproule prepared the report, valuation, statement or opinion referred to herein as having been prepared by Sproule; (ii) received by Sproule or by the "designated professionals" of Sproule, after the time specified above; or (iii) to be received by Sproule or by the "designated professionals" of Sproule; except in each case for the ownership of Common Shares, which in respect of Sproule and Sproule's "designated professionals", as a group, has at all relevant times represented less than one percent of the outstanding Common Shares. In addition, neither Sproule, nor any director, officer or employee of Sproule, is or is expected to be elected, appointed or employed as a director, officer or employee of the Corporation or of any associate or affiliate of the Corporation.

Deloitte LLP is independent within the meaning of the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta.

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of Reference

The Mandate and Terms of Reference of the audit committee (the "**Audit Committee**") of the Board is attached hereto as Schedule "C".

Composition of the Audit Committee

The Audit Committee is comprised of Messrs. Harry English (Chair), Don T. Gray, Greg Bay and Wilson Wang. The following chart sets out the assessment of each of the Audit Committee member's independence, financial literacy and relevant educational background and experience supporting such financial literacy.

Name, Province and Country of Residence	Independent	Financially Literate	Relevant Education and Experience
Don T. Gray Arizona, United States of America	Yes	Yes	Mr. Gray holds a BSc. in petroleum engineering from Texas A&M University and has over 30 years' experience in the Canadian oil and gas business in various capacities. Mr. Gray is a Co-Founder and former President and Chief Executive Officer of Peyto and is also Chairman and co-founder of Petrus Resources Ltd. and former Chairman of EIQ Capital Corp., a private investment company.
Harry English Alberta, Canada	Yes	Yes	Mr. English graduated with a Bachelor of Science (Honours) from the University of St. Andrews, Scotland in 1976 and is a Chartered Professional Accountant. He spent his 37-year career until May 2014 in professional practice, primarily in the energy business, most recently as a senior audit partner with Deloitte LLP.
Greg Bay Alberta, Canada	Yes	Yes	Mr. Bay obtained his Chartered Financial Analyst designation in 1988 and holds a Bachelor of Commerce in Finance from Brigham Young University. Mr. Bay is Managing Partner of Cypress Capital Management (founding partner) and brings with him over 28 years of experience in the investment industry with emphasis on the oil and gas sector.
Wilson Wang Hawaii, United States of America	Yes	Yes	Mr. Wang has his Chartered Financial Analyst designation and holds a Bachelor of Business Administration in Finance from the University of Hawaii. Mr. Wang is the Managing Partner and Founder of Twin Peaks Capital LLC, an investment management firm, since 2014, and founder of HFI Research, a research firm focused on the oil and gas industry since 2015.

Each of the members of the Audit Committee is considered "financially literate" and is considered "independent" within the meaning of National Instrument 52-110 – *Audit Committees*.

The Corporation believes that each of the members of the Audit Committee possesses: (a) an understanding of the accounting principles used by the Corporation to prepare its financial statements; (b) the ability to assess the general application of such accounting principles in connection with the accounting for estimates, accruals and reserves; (c) experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the Corporation's financial statements, or experience actively supervising one or more individuals engaged in such activities; and (d) an understanding of internal controls and procedures for financial reporting.

Pre-Approval of Policies and Procedures

The Corporation has adopted policies and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by Deloitte LLP. The Audit Committee will approve the provision of a specified list of audit and permitted non-audit services that the Audit Committee believes to be typical, reoccurring or otherwise likely to be provided by Deloitte LLP during the current fiscal year and the Audit Committee will be informed of each non-audit service, as applicable. The list of services will be sufficiently detailed as to the particular services to be provided to ensure that the Audit Committee knows precisely what services it is being asked to pre-approve and it will not be necessary for any member of management to make a judgment as to whether a proposed service fits within pre-approved services.

External Auditors Service Fees

The following table summarizes the fees billed to the Corporation by its auditors, Deloitte LLP, for external audit and other services during the periods indicated:

Year	Audit Fees(1)	Audit -Related Fees(2)	Tax Fees	All Other Fees(3)
	($)	($)	($)	($)
2022	245,405	6,420	-	2,392
2021	223,095	6,420	-	2,481

Notes:

(1) Represents the aggregate fees incurred by the Corporation in each of the last two fiscal years for audit services.

(2) Represents the aggregate fees incurred in each of the last two fiscal years by the Corporation for assurance and related services that are reasonably related to the performance of the audit or review of the Corporation's financial statements (and not reported under the heading "Audit Fees").

(3) Represents the aggregate fees billed in each of the last two fiscal years by the Corporation's external auditor for products and services not included under the headings "Audit Fees", "Audit Related Fees" and "Tax Fees". In both 2022 and 2021 these amounts relate to consulting fees paid to Deloitte LLP for Gear's regulatory, safety and environmental program.

INDUSTRY CONDITIONS

Companies operating in the Canadian oil and gas industry are 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 as well as with respect to the pricing and taxation of petroleum 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 Western Canadian oil and gas industry. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments governments may enact in the future.

The Corporation's assets and operations are regulated by administrative agencies that derive their authority from legislation enacted by the applicable level of government. Regulated aspects of the Corporation's upstream oil and natural gas business include all manner of activities associated with the exploration for and production of oil and natural gas, including, among other matters: (i) permits for the drilling of wells and construction of related infrastructure; (ii) technical drilling and well requirements; (iii) permitted locations and access to operation sites; (iv) operating standards regarding conservation of produced substances and avoidance of waste, such as restricting flaring and venting; (v) minimizing environmental impacts, including by reducing emissions; (vi) storage, injection and disposal of substances associated with production operations; and (vii) the abandonment and reclamation of impacted sites. In order to conduct oil and natural gas operations and remain in good standing with the applicable federal or provincial regulatory scheme, producers 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 in this regard can be costly and a breach of the same may result in fines or other sanctions.

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

Pricing and Marketing in Canada

Crude Oil

Oil producers are entitled to negotiate sales contracts directly with purchasers. As a result, macroeconomic and microeconomic market forces determine the price of oil. Worldwide supply and demand factors are the primary determinant of oil prices, but regional market and transportation issues also influence prices. The specific price that a producer receives will depend, in part, on oil quality, prices of competing products, distance to market, availability of transportation, value of refined products, supply/demand balance and contractual terms of sale.

Global oil markets have recovered significantly from price drops resulting from the COVID-19 pandemic. In 2022, oil prices rose to the highest levels since 2014 due to tight supply and a resurgence in demand. The Organization of Petroleum Exporting Countries ("**OPEC**") forecasts robust growth in world oil demand in 2023, spurred by the relaxation of China's zero-COVID policy. OPEC predicts global oil demand to rise by 2.25 million barrels per day in 2023, despite newly emerging COVID-19 variants, interest rate increases in major economies and other uncertainties with respect to the world economy.

In February 2022, Russian military forces invaded Ukraine. Ongoing military conflict between Russia and Ukraine has significantly impacted the supply of oil and gas from the region. In addition, certain countries including Canada and the United States have imposed strict financial and trade sanctions against Russia, which sanctions may have far reaching effects on the global economy in addition to the near term effects on Russia. The long-term impacts of the conflict remain uncertain.

Natural Gas

Negotiations between buyers and sellers determine 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.

Natural Gas Liquids ("NGLs")

The pricing of condensates and other NGLs such as ethane, butane and propane 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 of sale.

Exports from Canada

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

Transportation Constraints and Market Access

Capacity to transport production from Western Canada to Eastern Canada, the United States and other international markets has been, and continues to be, a major constraint on the exportation of crude oil, natural gas and NGLs. Although certain pipeline and other transportation projects have been announced or are underway, many proposed projects have been cancelled or delayed due to regulatory hurdles, court challenges and economic and 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.

Oil Pipelines

Under Canadian constitutional law, the development and operation of interprovincial and international pipelines fall within the federal government's jurisdiction and, under the CERA, new interprovincial and international pipelines 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 in this regard such that, even when projects are approved, they often face delays due to actions taken by provincial and municipal governments 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 also require approvals from several levels of government in the United States.

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.

Specific Pipeline Updates

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of political opposition in British Columbia, the federal government acquired the Trans Mountain Pipeline in August 2018. Following the resolution of a number of legal challenges and a second regulatory hearing, construction on the Trans Mountain Pipeline expansion commenced in late 2019. Earlier estimated at $12.6 billion, Trans Mountain increased the project budget to $30.9 billion in March 2023. The pipeline is expected to be in service in the first quarter of 2024, an extension from Trans Mountain's initial December 2022 estimate. The budget increase and in-service date delay have been attributed to, among other things, high global inflation, global supply chain challenges, the widespread flooding in British Columbia in late 2021, and unexpected major archeological discoveries.

In November 2020, the Attorney General of Michigan filed a lawsuit to terminate an easement that allows the Enbridge Line 5 pipeline system to operate below the Straits of Mackinac, attempting to force the lines comprising this segment of the pipeline system to be shut down. Enbridge Inc. stated in January 2021 that it intends to defy the shut down order, as the dual pipelines are in full compliance with U.S. federal safety standards. The Government of Canada invoked a 1977 treaty with the United States on October 4, 2021, triggering bilateral negotiations over the pipeline. In August 2022, the United States District Court for Western Michigan rejected the Attorney General of Michigan's efforts to move the dispute to Michigan state court, citing important federal interests at stake in having the dispute heard in federal court. Michigan's Attorney General appealed that decision, and the United States District Court granted the motion to appeal in February 2023.

In September 2022, the District Court of Wisconsin ruled in favour of the Bad River Band in its dispute with Enbridge Inc. over the Enbridge Line 5 pipeline system in that state. Stopping short of ordering the system to be shut down, the Court ruled that the Bad River Band is entitled to financial compensation, and ordered Enbridge Inc. to reroute the pipeline around Bad River territory within five years.

Natural Gas and Liquefied Natural Gas ("LNG")

Natural gas prices in Western Canada have 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 prices received in other North American regions.

Required repairs or upgrades to existing pipeline systems in Western Canada have also led to reduced capacity and apportionment of access, the effects of which have been exacerbated by storage limitations. In October 2020, TC Energy Corporation received federal approval to expand the Nova Gas Transmission Line system (the "**NGTL System**") and the expanded NGTL System was completed in April 2022.

Specific Pipeline and Proposed LNG Export Terminal Updates

While a number of LNG export plants have been proposed in Canada, regulatory and legal uncertainty, social and political opposition 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 producers in northeastern British Columbia to transport natural gas to the LNG Canada liquefaction facility and export terminal in Kitimat, British Columbia via the Coastal GasLink pipeline (the "**CGL Pipeline**"). Phase 1 of the LNG Canada project reached 70% completion in October 2022, with a completion target of 2025.

In May 2020, TC Energy Corporation sold a 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 regulatory approval, the CGL Pipeline has faced legal and social opposition. For example, protests involving the Hereditary Chiefs of the Wet'suwet'en First Nation and their supporters have delayed construction activities on the CGL Pipeline, although construction is proceeding. As of November 2022, construction of the CGL Pipeline was approximately 80% complete.

Woodfibre LNG Limited issued a notice to proceed with construction of the Woodfibre LNG project to its prime contractor in April 2022. The Woodfibre LNG project is located near Squamish, British Columbia, and upon completion will produce approximately 2.1 million tonnes of LNG per year. Major construction is set to commence in 2023, with substantial completion of the project expected in late 2027. In November 2022, Enbridge Inc. completed a transaction with Pacific Energy Corporation Limited, the owner of Woodfibre LNG Limited, to retain a 30% ownership stake in the project.

In addition to LNG Canada, the CGL Pipeline and the Woodfibre LNG project, a number of other LNG projects are underway at varying stages of progress, though none have reached a positive final investment decision.

Marine Tankers

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

International Trade Agreements

Canada is party to a number of international trade agreements with other countries around the world that generally provide for, among other things, preferential access to various international markets for certain Canadian export products. Examples of such trade agreements include the Comprehensive Economic and Trade Agreement ("**CETA**"), the Comprehensive and Progressive Agreement for Trans-Pacific Partnership and, most prominently, the United States Mexico Canada Agreement (the "**USMCA**"), which replaced the former North American Free Trade Agreement ("**NAFTA**") on July 1, 2020. Because the United States remains Canada's primary trading partner and the largest international market for the export of oil, natural gas and NGLs from Canada, the implementation of the USMCA could impact Western Canada's oil and gas industry as a whole, 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 Eastern Canada, Asia and Europe.

Canada is also party to the CETA, which provides for duty-free, quota-free market access for Canadian crude oil and natural gas products to the European Union. Following the United Kingdom's departure from the European Union on January 31, 2020, the United Kingdom and Canada entered into the Canada-United Kingdom Trade Continuity Agreement ("**CUKTCA**"), which replicates CETA on a bilateral basis to maintain the status quo of the Canada-United Kingdom trade relationship.

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

Land Tenure

Mineral rights

With the exception of Manitoba, each provincial government in Western Canada owns most of the mineral rights to the oil and natural gas located within their respective provincial borders. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits (collectively, "leases") for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments in lieu thereof. The provincial governments in Western Canada conduct regular land sales where oil and natural gas companies bid for the leases necessary to explore for and produce oil and natural gas owned by the respective provincial governments. These leases generally have fixed terms, but they can be continued beyond their initial terms if the necessary conditions are satisfied.

In response to COVID-19, the Government of Alberta, among others, announced measures to extend or continue Crown leases and permits that may have otherwise expired in the months following the implementation of pandemic response measures.

All of the provinces of 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 disposition. 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 new leases and licences. 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.

In addition to Crown ownership of the rights to oil and natural gas, private ownership of oil and natural gas (i.e. freehold mineral lands) also exists in Western Canada. Rights to explore for and produce privately owned 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 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 manages subsurface and surface leases in consultation with applicable Indigenous peoples, for the exploration and production of oil and natural gas on Indigenous reservations through An Act to Amend the Indian Oil and Gas Act and the accompanying regulations. The Corporation does not have operations on Indigenous reserve lands.

Surface rights

To develop oil and natural gas resources, producers must also have access rights to the surface lands required to conduct operations. For Crown lands, surface access rights can be obtained directly from the government. For private lands, access rights can be negotiated with the landowner. Where an agreement cannot be reached, however, each province has developed its own process that producers can follow to obtain and maintain the surface access necessary to conduct operations throughout the lifespan of a well, including notification requirements and providing compensation to affected persons for lost land use and surface damage. Similar rules apply to facility and pipeline operators.

Royalties and Incentives

General

Each province has legislation and regulations in place to govern Crown royalties and establish the royalty rates that producers must pay in respect of the production of Crown resources. 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 oil sands projects and oil, natural gas and NGL production. Royalties payable on production from lands where the Crown does not hold the mineral rights are negotiated between the mineral freehold owner and the lessee, though certain provincial taxes and other charges on production or revenues may be payable. Royalties from production on Crown lands are determined by provincial regulation and are generally calculated as a percentage of the value of production.

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

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

Alberta

Crown royalties

In Alberta, 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.

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, following which time they will become subject to the Modernized Framework. The Royalty Guarantee Act (Alberta), came into effect on July 18, 2019, and provides that no major changes will be made to the current oil and natural gas royalty structure for a period of at least 10 years.

Royalties on production from wells subject to 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 Alberta Energy Regulator (the "**AER**"), and incorporates information specific to each well such as vertical depth and lateral length.

Under the Modernized Framework, producers initially pay a flat royalty of 5% on production revenue from each producing well until payout, which is the point at which cumulative gross revenues from the well equals the applicable Drilling and Completion Cost Allowance. After payout, producers pay an increased royalty of up to 40% that will vary depending on the nature of the resource and market prices. Once the rate of production from a well is too low to sustain the full royalty burden, its royalty rate is gradually adjusted downward as production declines, eventually reaching a floor of 5%.

Under the Old Framework, royalty rates for conventional oil production can be as high as 40% and royalty rates for natural gas production can be as high as 36%. Similar to the Modernized Framework, these rates vary based on the nature of the resource and market prices. The natural gas royalty formula also provides for a reduction based on the measured depth of the well, as well as the acid gas content of the produced gas.

In addition to royalties, producers of oil and natural gas from Crown lands in Alberta are also required to pay annual rentals to the Government of Alberta.

Freehold royalties and taxes

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

The Government of Alberta levies annual freehold mineral taxes for production from freehold mineral lands. On average, the tax levied in Alberta is 4% of revenues reported from freehold mineral title properties and is payable by the registered owner of the mineral rights.

Incentives

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 coalbed methane wells, shale gas wells and horizontal crude oil and natural gas wells.

British Columbia

Crown royalties

On October 7, 2021, the Government of British Columbia launched a comprehensive review of its oil and gas royalty system. The new oil and gas royalty system (the "**New Framework**") was announced in May 2022. The New Framework will increase the minimum royalty rate from 3% to 5%, and eliminate the Deep Well, Marginal Well, Ultra-marginal Well, Low Productivity Well Rate Reduction and Clean Growth Infrastructure royalty programs (the "**Old Royalty Programs**"). New wells drilled under the New Framework will pay the flat royalty of 5% until capital spent on drilling and completions is recovered, at which point they will move to a price-sensitive royalty rate between 5% and 40%, depending on the specific commodity being produced.

Wells drilled on or after September 1, 2022 will not be eligible to qualify for the Old Royalty Programs, and will pay a 5% royalty rate for the equivalent of the first 12 months of production. Following this period, these wells will pay the prevailing price-sensitive royalty rates until September 1, 2024 when all wells will be transitioned to the New Framework. Wells drilled prior to September 1, 2022 will pay royalties based on the current framework until September 1, 2024, at which time those wells will be transitioned to the New Framework and will no longer be able to take advantage of the Old Royalty Programs.

Under the current system, Crown royalties payable on the production of oil and natural gas in British Columbia vary by market price, well type and the characteristics of the substances being produced. Producers of oil and natural gas receive royalty invoices each month for every well or unitized tract that is producing and/or reporting sales.

The Crown royalty rate for oil can be as high as 40% and depends on factors such as the volume of oil produced from a particular well or unitized tract and its vintage. Royalty rates are reduced on certain wells under the Old Royalty Programs to reflect higher per-unit costs of exploration and extraction. The Crown royalty rate for natural gas and NGLs in British Columbia varies depending on the characteristics of the specific substance and can be as high as 27%, depending on factors such as whether the gas is classified as conservation gas or non-conservation gas, the applicable reference price and select price.

Freehold royalties and taxes

Royalty rates for the production of privately owned oil and natural gas are negotiated between the producer and the resource owner. In addition to these negotiated royalties, producers of oil and natural gas from freehold lands in British Columbia also pay monthly freehold production taxes to the Government of British Columbia.

For oil, the applicable freehold production tax is based on the volume of monthly production, which is either a flat rate, or, beyond a certain production level, is determined using a sliding scale formula based on the production level. For natural gas, the applicable freehold production tax is a flat rate, or, at certain production levels, is determined using a sliding scale formula based on a reference price, and depends on whether the natural gas is conservation gas or non-conservation gas. Additionally, owners of mineral rights in British Columbia must pay an annual mineral land tax to the Government of British Columbia.

Saskatchewan

Crown royalties

Crown royalties payable on the production of oil and natural gas in Saskatchewan are paid on a well-by-well basis. Producers of oil and natural gas receive royalty invoices from the Government of Saskatchewan on a monthly basis.

The Crown royalty payable on oil production is paid on a well-by-well basis and depends on a number of variables, including the type and vintage of oil, the quantity of oil produced in a given month, the average wellhead price and certain price adjustment factors. Based on these factors, the base royalty rate ranges from 5% - 20% and the marginal royalty rate ranges from 25% - 45%. Base royalty rates represent the minimum royalty rate payable on production of petroleum substances, regardless of the level of production. Marginal royalty rates charge increasing royalty rates as the level of production increases. Marginal royalty rates, such as those used in Saskatchewan's royalty regime, are designed to allow producers of petroleum products to more quickly recover initial investments at the beginning of a project's life cycle. The Crown royalty payable on natural gas production 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 and classification of the natural gas, the finished drilling date of the well and certain price adjustment factors. Based on these factors, the base royalty rate ranges from 0% - 20% and the marginal royalty rate ranges from 30% - 45%.

Freehold royalties and taxes

Royalty rates for the production of privately owned 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 determining the Crown royalty rate, and then subtracting a calculated production tax factor that depends on the classification of the petroleum substance produced. Additionally, a mineral rights tax is charged to mineral rights holders paid on an annual basis at the rate of $3.70 per-hectare owned regardless of whether or not there is production from the lands.

Resource Surcharge

In addition to royalties, certain entities operating in Saskatchewan must pay a tax, known as a "**Resource Surcharge**", on the value of resources sales. The Resource Surcharge rate is 3% of the sales value of all oil and natural gas produced from wells drilled in Saskatchewan before October 1, 2002, and 1.7% for any wells drilled thereafter.

Regulatory Authorities and Environmental Regulation

General

The Canadian oil and gas industry is subject to environmental regulation under a variety of Canadian federal, provincial, territorial, and municipal laws and regulations, all of which are subject to governmental review and revision from time to time. Such regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. 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 such regulations can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability, and the imposition of material fines and penalties. In addition, future changes to environmental legislation, including legislation related to air pollution and greenhouse gas ("**GHG**") emissions (typically measured in terms of their global warming potential and expressed in terms of carbon dioxide equivalent ("**CO2e**")), may impose further requirements on operators and other companies in the oil and gas industry.

Federal

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

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

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

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

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

Alberta

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

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

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

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

The AER has developed monitoring and reporting requirements that apply to all oil and natural gas producers working in certain areas where the likelihood of an earthquake is higher. The Corporation does not currently anticipate that it will have any material operations in areas with heightened seismic protocols; however, in the future it is possible that heightened seismic protocols could impact the Corporation's operations.

British Columbia

In British Columbia, the Oil and Gas Activities Act (the "**OGAA**") regulates conventional oil and natural gas producers, shale gas producers and other operators of oil and natural gas facilities in the province. Under the OGAA, the British Columbia Energy Regulator ("**BCER**") has broad powers, particularly with respect to compliance, enforcement and the setting of technical safety and operational standards for oil and natural gas activities. The Environmental Protection and Management Regulation establishes the government's environmental objectives and requires the BCER to consider these environmental objectives in deciding whether or not to authorize a particular activity. In addition, the Petroleum and Natural Gas Act, in conjunction with the OGAA, requires proponents to obtain various approvals before undertaking exploration or production work. Such approvals are given subject to environmental considerations and permits, licences and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

In November 2022, the Government of British Columbia passed the Energy Statutes Amendment Act, 2022 (the "**ESA Act**"). The ESA Act changed the name of the British Columbia Oil and Gas Commission ("**BC OGC**") to the BCER, and, when the relevant sections are brought into force, will expand the BCER's mandate to include oversight of hydrogen, ammonia and methanol. In support of the government's stated desire to transition away from fossil fuels and grow the province's hydrogen industry, the OGAA will also be renamed the Energy Resources Activities Act (the "**ERAA**"). In addition to expanding the BCER's jurisdiction to include hydrogen, ammonia and methanol, the updated ERAA will also expand director and officer responsibility for costs associated with orphan sites.

The Government of British Columbia has introduced a regime to monitor and manage the risk of induced seismicity related to oil and natural gas operations, particularly in northern British Columbia, where hydraulic fracturing is used to access natural gas plays. The Drilling and Production Regulation requires a producer to suspend its operations if they trigger an earthquake with a magnitude on the Richter scale of 4.0 or greater, and to implement mitigation measures approved by the BCER before resuming production. The permitting process requires all natural gas producers to conduct ground monitoring, and to submit a ground monitoring report within 30 days of completing hydraulic fracturing operations.

In May 2018, the BC OGC (as the BCER was then named) issued a Special Project Order under section 75 of the OGAA, which designated the Kiskatinaw Seismic Monitoring and Mitigation Area, spanning between Fort St. John and Dawson Creek (the "**Kiskatinaw Area**"). The BC OGC (as the BCER was then named) introduced enhancements to the Special Project Order in April 2021, expanding the boundaries of the order. Under the enhanced Special Project Order, a magnitude 3.0 or above seismic event will result in the immediate suspension of fracturing activities from the suspected well(s) for a minimum of five calendar days. Future earthquakes outside of the Kiskatinaw Area may trigger the introduction of similar requirements elsewhere in the province.

An updated Environmental Assessment Act came into force in December 2019. The new assessment regime subjects proposed projects to an enhanced environmental review process that, among other things, emphasises early engagement and aims to enhance Indigenous engagement in the project approval process with an emphasis on consensus-building. Simultaneously with the enactment of the Environmental Assessment Act, the Government of British Columbia enacted the accompanying

Reviewable Projects Regulation, which sets out the projects subject to the new regime. The "project list" captures industrial, mining, energy, water management, waste disposal, transportation and other GHG intensive projects. In conducting an environmental assessment, the British Columbia Environmental Assessment Office will consider the environmental, health, cultural, social and economic effects of a proposed project.

Saskatchewan

The Saskatchewan Ministry of Energy and Resources is the primary regulator of oil and natural gas activities in the province. *The Oil and Gas Conservation Act* (the "**SKOGCA**") is the statute 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 an 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 a partner in the Petrinex Database. The Petrinix Database delivers business processes and information required for the assessment, levy, and collection of crown royalties for Alberta, Saskatchewan, Manitoba and British Columbia. It provides information in support of the regulatory mandates and legislation of the provinces, and services that facilitate important industry commercial activities, including partner to partner reporting, oil marketing, financial analytics, compliance assurance and production accounting.

Liability Management

Alberta

The AER administers the Liability Management Framework (the "**AB LM Framework**") and the Liability Management Rating Program (the "**AB LMR Program**") to manage liability for most conventional upstream oil and natural gas wells, facilities and pipelines in Alberta. The AER is in the process of replacing the AB LMR Program with the AB LM Framework. This change was effected under key new AER directives in 2021, and further updates released in 2022. Broadly, the AB LM Framework is intended to provide a more holistic approach to liability management in Alberta, as the AER found that the more formulaic approach under the AB LMR Program did not necessarily indicate whether a company could meet its liability obligations. New developments under the AB LM Framework include a new Licensee Capability Assessment System (the "**AB LCA**"), a new Inventory Reduction Program (the "**AB IR Program**"), and a new Licensee Management Program ("**AB LM Program**"). Meanwhile, some programs under the AB LMR Program remain in effect, including the Oilfield Waste Liability Program (the "**AB OWL Program**"), the Large Facility Liability Management Program (the "**AB LF Program**") and elements of the Licensee Liability Rating Program (the "**AB LLR Program**"). The mix between active programs under the AB LM Framework and the AB LMR Program highlights the transitional and dynamic nature of liability management in Alberta. While the province is moving towards the AB LM Framework and a more holistic approach to liability management, the AER has noted that this will be a gradual process that will take time to complete. In the meantime, the AB LMR Program continues to play an important role in Alberta's liability management scheme.

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

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

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

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

In addition to the AB LCA, Directive 088 also implemented other new liability management programs under the AB LM Framework. These include the AB LM Program and the AB IR Program. Under the AB LM Program the AER will continuously monitor licensees over the life-cycle of a project. If, under the AB LM Program, the AER identifies a licensee as high risk, the regulator may employ various tools to ensure that a licensee meets its regulatory and liability obligations. In addition, under the AB IR Program the AER sets industry-wide spending targets for abandonment and reclamation activities. Licensees are then assigned a mandatory licensee specific target based on the licensee's proportion of provincial inactive liabilities and the licensee's level of financial distress. Certain licensees may also elect to provide the AER with a security deposit in place of their closure spend target. The AER has also indicated that it will implement a closure nomination program (the "**CN Program**") in 2023. Under the program, those who qualify may nominate certain oil and gas sites for closure. Details regarding the CN Program and the mechanism through which nominated sites will be abandoned and reclaimed are forthcoming.

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

To address abandonment and reclamation liabilities in Alberta, the AER also implements, from time to time, programs intended to encourage the decommissioning, remediation and reclamation of inactive or marginal oil and natural gas infrastructure. In 2018, for example, the AER announced a voluntary area-based closure ("**ABC**") program. The ABC program is designed to reduce the cost of abandonment and reclamation operations though industry collaboration and economies of scale. Parties seeking to participate in the program must commit to an inactive liability reduction target to be met through closure work performed on inactive assets. The Corporation has abandoned or reclaimed certain sites as part of the ABC program.

British Columbia

Similar to Alberta, the BCER has moved away from the formulaic approach to liability management set out in the Liability Management Rating Program, towards a more holistic assessment of a permit holder's ability to meet its abandonment and reclamation obligations. The BC OGC (as the BCER was then named) implemented the Permittee Capability Assessment on April 1, 2022 (the "**BC PCA**"). Under the BC PCA, the financial risk of a permit holder is assessed based on its: (i) assets to liabilities ratio; (ii) net profit margin (three-year average); (iii) interest coverage ratio; (iv) cash flow to debt ratio; and (v) debt to equity ratio. A permit holder is assessed on these factors based on the financial information it is required to submit to the BCER intermittently throughout the year. The permit holder is then evaluated on the magnitude of its liabilities, based on the deemed abandonment, assessment, remediation and reclamation liability associated with the permit holder's dormant, inactive, and marginal sites. If the BCER deems a permit holder to be high-risk under the BC PCA based on its financial risk and the magnitude of its liabilities, the regulator may require that permit holder to engage in corrective action. Corrective action could include the submission of security deposits and/or the completion of liability reduction work. Regarding the latter, the BCER will attempt to engage with permit holders to develop corrective action plans prior to issuing corrective action requirements.

In the spring of 2019, a liability-based levy paid to the Orphan Site Reclamation Fund ("**OSRF**") replaced the orphan site reclamation fund tax paid by permit holders. Similar to Alberta's Orphan Fund, the OSRF is an industry-funded program created to address the abandonment and reclamation costs for orphan sites. Permit holders are required to pay their proportionate share of the levy. The OGAA permits the BCER to impose more than one levy in a given calendar year.

The Dormancy and Shutdown Regulation (the "**Dormancy Regulation**") establishes the first set of legally imposed timelines for the restoration of oil and natural gas wells in Western Canada. The Dormancy Regulation classifies different sites based on activity levels associated with each site, with a goal of ensuring that 100% of currently dormant sites are reclaimed by 2036 with additional regulated timelines for sites that become dormant between 2019 and 2023 or become dormant after 2024. A permit holder will have varying reporting, decommissioning, remediation and reclamation obligations that depend on the classification of its sites. Any permit holder that has a dormant site in its portfolio must develop and submit an annual work plan to the BCER, outlining its decommissioning and restoration activities for each calendar year. The permit holder must also prepare and submit a retrospective annual report within 60 days of the end of the calendar year in which it conducted the work outlined in the corresponding annual work plan.

The Government of British Columbia passed amendments to the Oil and Gas Activities Act under the Miscellaneous Statutes Amendment Act (No.2) in October 2021. These amendments allow the BCER to grant exemptions for strict compliance with the requirements of the Dormancy Regulation. In turn, this may mean that a permit holder can, with approval, depart from the regulated timelines set out under the Dormancy Regulation. The relevant amendments which provide the BCER with the power to grant these exemptions came into force on October 28, 2021.

Saskatchewan

The Saskatchewan Ministry of Energy and Resources administrates the Licensee Liability Rating Program (the "**SK LLR Program**"), which was updated in January 2023. 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 the 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 the Saskatchewan Ministry of Energy and Resources confirms there is no legally responsible or financially able party to deal with the abandonment and/or reclamation responsibilities. The SK LLR Program also outlines requirements for security deposits and licence transfers. If a licence holder wishes to transfer a licence, a licence transfer application must be completed through the Integrated Resource Information System ("**IRIS**"). An assessment is conducted on both the transferee and the transferor listed in the IRIS application. To complete the assessment, both a licensee liability rating ("**LLR**") assessment and a proportional risk transfer is conducted. If a licence transfer will result in either the transferor or transferee having an LLR of less than 1.0, the transferor or transferee, as applicable, must submit the amount of security deposit required by the minister.

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 came into force on January 1, 2023.

The Closure Regulations include: (i) changes to the formula for determining if a licensee poses a risk; (ii) annual spend targets for closure activities by licensees; 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. 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.

Climate Change Regulation

Climate change regulation at each of the international, federal and provincial levels has the potential to significantly affect the future of the oil and gas industry in Canada. These impacts are uncertain and it is not possible to predict what future policies, laws and regulations will entail. 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.

Federal

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

During the course of the 2021 United Nations Climate Change Conference in Glasgow, Scotland, Canada's Prime Minister Justin Trudeau made several pledges aimed at reducing Canada's GHG emissions and environmental impact, including: (i) reducing methane emissions in the oil and gas sector to 75% of 2012 levels by 2030; (ii) ceasing the export of thermal coal by 2030; (iii) imposing a cap on emissions from the oil and gas sector; (iv) halting direct public funding to the global fossil fuel sector by the end of 2022; and (v) committing that all new vehicles sold in the country will be zero-emission on or before 2040.

In line with the Prime Minister's pledge to impose a cap on emissions from the oil and gas sector, the federal government published a discussion paper on July 18, 2022 that outlines two potential regulatory options for such a cap. Those proposed options are either to: (i) implement a new cap-and-trade system that would set a limit on emissions from the sector; or (ii) modify the existing pollution pricing benchmark (as discussed below) to limit emissions from the sector. These options are currently under review and interested parties had the opportunity to make submissions regarding the proposed cap, ending in September 2022. The form of emissions cap on the oil and gas sector and the overall effect of such a cap remain uncertain.

The Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change in 2016, setting out a plan to meet the federal government's 2030 emissions reduction targets. On June 21, 2018, the federal government enacted the Greenhouse Gas Pollution Pricing Act (the "**GGPPA**"), which came into force on January 1, 2019. This regime has two parts: an output-based pricing system ("**OBPS**") for large industry (enabled by the Output-Based Pricing System Regulations) and a fuel charge (enabled by the Fuel Charge Regulations), both of which impose a price on CO2e emissions. This system applies in provinces and territories that request it and in those that do not have their own equivalent emissions pricing systems in place that meet the federal standards and ensure that there is a uniform price on emissions across the country. Originally under the federal plans, the price was set to escalate by $10 per year until it reached a maximum price of $50/tonne of CO2e in 2022; however, on December 11, 2020, the federal government announced its intention to continue the annual price increases beyond 2022. Commencing in 2023, the benchmark price per tonne of CO2e will increase by $15 per year until it reaches $170/tonne of CO2e in 2030. Effective January 1, 2023, the minimum price permissible under the GGPPA rose to $65/tonne of CO2e.

While several provinces challenged the constitutionality of the GGPPA following its enactment, the Supreme Court of Canada confirmed its constitutional validity in a judgment released on March 25, 2021.

On April 26, 2018, the federal government passed the Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) (the "**Federal Methane Regulations**"). The Federal Methane Regulations seek to reduce emissions of methane from the oil and natural gas sector, and came into force on January 1, 2020.

By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and the intentional venting of methane and ensure that oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and natural gas facilities are permitted to vent. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

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

In the November 23, 2021 Speech from the Throne, the federal government restated its commitment to achieve net-zero emission by 2050. In pursuit of this objective, the government's proposed actions include: (i) moving to cap and cut oil and gas sector emissions; (ii) investing in public transit and mandating the sale of zero-emission vehicles; (iii) increasing the federally imposed price on pollution; (iv) investing in the production of cleaner steel, aluminum, building products, cars, and planes; (v) addressing the loss of biodiversity by continuing to strengthen partnerships with First Nations, Inuit, and Métis to protect nature and the traditional knowledge of those groups; (vi) creating a Canada Water Agency to safeguard water as a natural resource and support Canadian farmers; (vii) strengthening action to prevent and prepare for floods, wildfires, droughts, coastline erosion, and other extreme weather worsened by climate change; and (viii) helping build back communities impacted by extreme weather events through the development of Canada's first-ever National Adaptation Strategy.

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

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

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

On June 20, 2022, the Clean Fuel Regulations came into force, establishing Canada's Clean Fuel Standard. The Clean Fuel Standard will replace the former Renewable Fuels Regulation, and aims to discourage the use of fossil fuels by increasing the price of those fuels when compared to lower-carbon alternatives. Coming into force in 2023, the Clean Fuel Standard will impose obligations on primary suppliers of transportation fuels in Canada and require fuels to contain a minimum percentage of renewable fuel content and meet emissions caps calculated over the life cycle of the fuel. The Clean Fuel Regulations also establish a market for compliance credits. Compliance credits can be generated by primary suppliers, among others, through carbon capture and storage, producing or importing low-emission fuel, or through end-use fuel switching (for example, operating an electric vehicle charging network).

The Government of Canada is also in the midst of developing a carbon capture utilization and storage ("**CCUS**") strategy. CCUS is a technology that captures carbon dioxide from facilities, including industrial or power applications, or directly from the atmosphere. The captured carbon dioxide is then compressed and transported for permanent storage in underground geological formations or used to make new products such as concrete. Beginning in 2022, the federal government plans to spend $319 million over seven years to ramp up CCUS in Canada, as this is expected to be a critical element of the plan to reach net-zero by 2050.

Alberta

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

In June 2019, the fuel charge element of the federal backstop program took effect in Alberta. On January 1, 2023, the carbon tax payable in Alberta increased from $50 to $65 per tonne of CO2e, and will continue to increase at a rate of $15 per year until it reaches $170 per tonne in 2030. In December 2019, the federal government approved Alberta's Technology Innovation and Emissions Reduction ("**TIER**") regulation, which applies to large emitters. The TIER regulation came into effect on January 1, 2020 (as amended on January 1, 2023) and replaced the previous Carbon Competitiveness Incentives Regulation. The TIER regulation meets the federal benchmark stringency requirements for emissions sources covered in the regulation, but the federal backstop continues to apply to emissions sources not covered by the regulation.

The TIER regulation applies to emitters that emit more than 100,000 tonnes of CO2e per year in 2016 or any subsequent year. The initial target for most TIER-regulated facilities is to reduce emissions intensity by 10% as measured against that facility's individual benchmark, with a further 2% reduction in each subsequent year. The facility-specific benchmark does not apply to all facilities, such as those in the electricity sector, which 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. Under the TIER regulation, certain facilities in high-emitting or trade exposed sectors can opt-in to the program in specified circumstances if they do not meet the 100,000 tonne threshold. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports. 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 Government of Alberta aims to lower annual methane emissions by 45% by 2025. The Government of Alberta enacted the Methane Emission Reduction Regulation on January 1, 2020, and in November 2020, the Government of Canada and the Government of Alberta announced an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in Alberta.

British Columbia

In August 2016, the Government of British Columbia launched its Climate Leadership Plan, which aims to reduce British Columbia's net annual emissions by up to 25 million tonnes below current forecasts by 2050 and recommit the province to achieving its target of reducing emissions by 80% below 2007 levels by 2050. British Columbia was also the first Canadian province to implement a revenue-neutral fuel charge. The fuel charge is currently set at $65/tonne of CO2e, and will continue to increase in line with the GGPPA minimum charge. Federal carbon pricing mechanisms are not currently in force in British Columbia, as the province's programs currently meet or exceed the federal benchmark stringency requirements.

In January 2016, the Greenhouse Gas Industrial Reporting and Control Act (the "**GGIRCA**") came into effect, which streamlined the regulatory process for large emitting facilities. The GGIRCA sets out various performance standards for different industrial sectors and provides for emissions offsets through the purchase of credits or through emission offsetting projects.

In December 2018, the Government of British Columbia announced an updated clean energy plan, "**CleanBC**", which seeks to ensure that British Columbia achieves 75% of its GHG emissions reduction target by 2030. The CleanBC plan includes a number of strategies targeting the industrial, transportation, construction, and waste sectors of the British Columbia economy. Key initiatives include: (i) increasing the generation of electricity from clean and renewable energy sources; (ii) imposing a 15% renewable content requirement in natural gas by 2030; (iii) requiring fuel suppliers to reduce the carbon intensity of diesel and gasoline by 20% by 2030; (iv) investing in the electrification of oil and natural gas production; (v) reducing 45% of methane emissions associated with natural gas production; and (vi) incentivizing the adoption of zero-emissions vehicles. Complementing its CleanBC plan, on March 26, 2021, the Government of British Columbia announced a number of sector-specific emissions reduction targets, established with reference to 2007 emissions levels, that it aims to achieve by 2030, including reduction targets of 27-32% for the transportation sector, 38-43% for industry and 33-38% for oil and gas.

The Government of British Columbia established the CleanBC Industry Fund in 2019 to support clean industry development in the province. The fund uses a portion of carbon tax revenue paid by large emitters to invest in projects aimed at reducing greenhouse gas emissions. In March 2021, the Government of British Columbia temporarily increased the provincial share of funding to up to 90% of project costs with a cap of $25 million per project. In 2021, the CleanBC Industry Fund invested $83.5 million in 32 emissions performance projects across British Columbia.

In October 2021, the Government of British Columbia announced a more ambitious climate change plan called the CleanBC Roadmap to 2030 (the "**CleanBC Roadmap**"), aimed at helping British Columbia achieve its 2030 emission reduction targets established under the CleanBC plan. The CleanBC Roadmap includes plans for, among other things, laws requiring 90% of new passenger vehicles sold in the province to be zero-emission by 2030, all new buildings to be zero-carbon beginning in 2030, the electrification of public transit and ferries, and for increased support for clean hydrogen and negative emissions technology. Further, the CleanBC Roadmap plans to increase carbon taxation in the province to meet or exceed the federal GGPPA benchmark.

In January 2020, the BC OGC (as the BCER was then named) implemented a series of amendments to the British Columbia Drilling and Production Regulation that will require facility and well permit holders to, among other things, reduce natural gas leaks and curb monthly natural gas emissions from their equipment and operations. In November 2020, the Government of Canada and the Government of British Columbia announced that they had finalized an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in British Columbia.

Saskatchewan

In May 2009, the Government of Saskatchewan announced the *Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. The government subsequently released *Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy* ("**Prairie Resilience**"), outlining its strategy to reduce GHG emissions by 12 million tonnes by 2030.

Under the MRGGA, facilities that have annual GHG emissions in excess of 10,000 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 40-45% 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 of CO2e by 2030.

The MRGGA and the Saskatchewan O&G Emissions Regulations meet the federal benchmark stringency requirements for certain industrial sectors, but the federal backstop continues to apply to emissions sources not covered in Saskatchewan's emissions legislation. The federal fuel charge continues to apply in Saskatchewan.

In April 2019, Saskatchewan produced its first annual report on climate resilience. The report measures the Province's progress on goals set out under Prairie Resilience. Among these goals is the aim of increasing the role of renewable energy in the provincial energy mix to 50% by 2030. According to its 2020 and 2021 reports, the province generates nearly 26% of its electricity from renewable energy sources, an increase of 1.6% since 2019.

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 revised in August 2022, and *Directive PNG036: Venting and Flaring Requirements*, which came into force in April 2020 and was last revised in June 2022. 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 in Saskatchewan. 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 CCUS through enhanced oil recovery projects. In November 2021, Saskatchewan announced that pipelines transporting CO2 for CCUS are eligible for the provincial Oil Infrastructure Investment Program ("**OIIP**"). The Government of Saskatchewan expects that CCUS projects will attract provincial investment of more than $2 billion and sequester over two million tonnes of CO2 annually. OIIP will assist in generating a total investment impact of at least $500 million in new and expanded pipeline capacity in Saskatchewan, while encouraging industry adoption of CCUS and further reductions in GHG emissions.

Indigenous Rights

Constitutionally mandated government-led consultation with and, if applicable, accommodation of, the rights of Indigenous groups impacted by regulated industrial activity, as well as proponent-led consultation and accommodation or benefit sharing initiatives, play an increasingly important role in the Western Canadian oil and gas industry. In addition, Canada is a signatory to the 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 June 2021, the United Nations Declaration on the Rights of Indigenous Peoples Act ("**UNDRIP Act**") came into force in Canada. Similar to British Columbia's DRIPA, the UNDRIP Act requires the Government of Canada to take all measures necessary to ensure the laws of Canada are consistent with the principles of UNDRIP and to implement an action plan to address UNDRIP's objectives. On June 21, 2022, the Minister of Justice and Attorney General issued the First Annual Progress Report on the implementation of the UNDRIP Act (the "**Progress Report**"). The Progress Report provides that, as of June 2022, the federal government has sought to implement the UNDRIP Act by, among other things, creating a Secretariat within the Department of Justice to support Indigenous participation in the implementation of UNDRIP, consulting with Indigenous peoples to identify their priorities, drafting an action plan to align federal laws with UNDRIP, and implementing efforts to educate federal departments on UNDRIP's principles.

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

On June 29, 2021, the British Columbia Supreme Court issued a judgement in Yahey v British Columbia (the "**Blueberry Decision**"), in which it determined that the cumulative impacts of industrial development on the traditional territory of the Blueberry River First Nation ("**BRFN**") in northeast British Columbia had breached the BRFN's rights guaranteed under Treaty 8. The Blueberry Decision may have significant impacts on the regulation of industrial activities in northeast British Columbia, and may lead to similar claims of cumulative effects across Canada in other areas covered by numbered treaties, as has been seen in Alberta.

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

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

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

RISK FACTORS

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

Prices, Markets and Marketing

Various factors may adversely impact the marketability of oil and natural gas, affecting net production revenue, production volumes and development and exploration activities

The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire capacity in pipelines that deliver oil, NGLs and natural gas to commercial markets or contract for the delivery of crude oil and NGLs by rail. Numerous factors beyond the Corporation's control do, and will continue to, affect the marketability and price of oil and natural gas acquired, produced, or discovered by the Corporation, including:

- deliverability uncertainties related to the distance the Corporation's reserves are from pipelines, railway lines and processing and storage facilities;
- operational problems affecting pipelines, railway lines and processing and storage facilities; and
- government regulation relating to prices, taxes, royalties, land tenure, allowable production and the export of oil and natural gas.

Oil and natural gas prices are expected to remain volatile for a variety of reasons including market uncertainties over the supply and demand of these commodities due to the current state of the world economies, the ongoing COVID-19 pandemic, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries and conflicts in the Middle East. Prices for oil and natural gas are also subject to the availability of foreign markets and the Corporation's ability to access such markets. A material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

See "*Industry Conditions – Transportation Constraints and Marketing*".

Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for, and project the return on, acquisitions and development and exploitation projects.

Exploration, Development and Production Risks

The Corporation's future performance may be affected by the financial, operational, environmental and safety risks associated with the exploration, development and production of oil and natural gas

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

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

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

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

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

As is standard industry practice, the Corporation is not fully insured against all risks, nor are all risks insurable. Although the Corporation maintains liability insurance and business interruption insurance for the facility assets in Tableland, Saskatchewan in an amount that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. See "*Risk Factors – Insurance*". In either event, the Corporation could incur significant costs.

Dividends

The Corporation's payment of future dividends are not guaranteed and the Board has discretion on whether such dividends will be declared and paid

Regular and special dividends are not guaranteed and could fluctuate with the performance of the Corporation. The Board has the discretion to determine the amount of dividends to be declared and paid to shareholders each month. In determining the level of dividends, the Board will take into consideration numerous factors, including current and expected future levels of earnings; cash flow from operating activities; results of operations; income taxes; capital expenditures; working capital requirements; current and potential future environmental liabilities; the impact of interest rates and/or foreign exchange rates; crude oil prices; financial condition of the Corporation; the need for funds to finance ongoing operations and other considerations, as the Board considers relevant. Dividends may be increased, reduced, suspended or eliminated entirely depending on the Corporation's operations and the performance of its assets and businesses.

Market Price of Common Shares

The trading price of the Common Shares may be adversely affected by factors related and unrelated to the crude oil and natural gas industry

The trading price of the securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to the Corporation's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices, and/or current perceptions of the crude oil and natural gas market. In recent years, the volatility of commodities has increased due, in part, to the implementation of computerized trading and the decrease of discretionary commodity trading. In addition, the volatility, trading volume and share price of issuers have been impacted by increasing investment levels in passive funds that track major indices, as such funds only purchase securities included in such indices. In addition, in certain jurisdictions, institutions, including government sponsored entities, have determined to decrease their ownership in oil and natural gas entities which may impact the liquidity of certain securities and put downward pressure on the trading price of those securities. Similarly, the market price of the Common Shares could be subject to significant fluctuations in response to variations in the Corporation's operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which the Common Shares will trade cannot be accurately predicted.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The anticipated benefits of acquisitions may not be achieved and the Corporation may dispose of non-core assets for less than their carrying value on the financial statements as a result of weak market conditions

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

Inflation and Cost Management

A failure to secure the services and equipment necessary to the Corporation'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 cash flows.

The Canada and global economies have recently experienced high rates of inflation, which has had an impact on the Corporation's operating costs and capital expenditures. The Corporation'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 cash flows.

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 the Corporation'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 cash flows.

Political Uncertainty

The Corporation's business may be adversely affected by political and social events and decisions made in Canada and elsewhere

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

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

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

Project Risks

The success of the Corporation's operations may be negatively impacted by factors outside of its control resulting in operational delays, and cost overruns

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

- availability of processing capacity;

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

Because of these factors, the Corporation could be unable to execute projects on time, on budget, or at all.

Reliance on a Skilled Workforce and Key Personnel

An inability to recruit and retain a skilled workforce and key personnel may negatively impact the Corporation

The operations and management of the Corporation require the recruitment and retention of a skilled workforce, including engineers, technical personnel and other professionals. The loss of key members of such workforce, or a substantial portion of the workforce as a whole, could result in the failure to implement the Corporation's business plans which could have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Competition for qualified personnel in the crude oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. The Corporation does not have any key personnel insurance in effect. Contributions of the existing management team to the immediate and near term operations of the Corporation are likely to be of central importance. In addition, certain of the Corporation's current employees are senior and have significant institutional knowledge that must be transferred to other employees prior to their departure from the workforce. If the Corporation is unable to: (i) retain current employees; (ii) successfully complete effective knowledge transfers; and/or (iii) recruit new employees with the requisite knowledge and experience, the Corporation could be negatively impacted. In addition, the Corporation could experience increased costs to retain and recruit these professionals.

Gathering and Processing Facilities, Pipeline Systems, Trucking and Rail

Lack of capacity and/or regulatory constraints on gathering and processing facilities, pipeline systems and railway lines may have a negative impact on the Corporation's ability to produce and sell its oil and natural gas

The Corporation delivers its products through gathering and processing facilities and pipeline systems. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities and pipeline systems. The lack of firm pipeline capacity, production limits and limits on availability of capacity in gathering and processing facilities, pipeline systems or railway lines continues to affect the oil and natural gas industry and limits the ability to transport produced oil and natural gas to market. In addition, the pro-rationing of capacity on interprovincial pipeline systems from time to time affects the ability of oil and natural gas companies to export oil and natural gas, and could result in our inability to realize the full economic potential of our production or in a reduction of the price we receive for our products. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the Corporation's production, operations and financial results.

Federal and various provincial governments have been active in recent years in their support for and opposition to major infrastructure projects in Canada leading to increased awareness of, and challenges to, interprovincial and international infrastructure projects. In 2019, with the passing of Bill C-69, CERA and the *Impact Assessment Act* came into force and the *National Energy Board Act* and the *Canadian Environmental Assessment Act, 2012* were repealed. In addition, the IA Agency of Canada replaced the Canadian Environmental Assessment Agency. The impact of the new federal regulatory scheme on proponents, and the timing for receipt of approvals, of major projects is unclear.

A portion of the Corporation's production may, from time to time, be processed through facilities owned by third parties and over which the Corporation does not have control. From time to time, these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a material adverse effect on the Corporation's ability to process its production and deliver the same to market. Midstream and pipeline companies may take actions to maximize their return on investment, which may in turn adversely affect producers and shippers, especially when combined with a regulatory framework that may not always align with the interests of particular shippers.

Operational Dependence

The successful operation of a portion of the Corporation's properties is dependent on third parties

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

In addition, due to the low and volatile commodity prices, many companies, including companies that may operate some of the assets in which the Corporation has an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which the Corporation has an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations, the Corporation may be required to satisfy such obligations and to seek reimbursement from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, the Corporation potentially becoming subject to additional liabilities relating to such assets and the Corporation having difficulty collecting revenue due from such operators or recovering amounts owing to the Corporation from such operators for their share of abandonment and reclamation obligations. Any of these factors could have a material adverse affect on the Corporation's financial and operational results. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management*" and "*Risk Factors – Third Party Credit Risk"*.

Variations in Foreign Exchange Rates and Interest Rates

Variations in foreign exchange rates and interest rates could adversely affect the Corporation's financial condition

World oil and natural gas prices are quoted in United States dollars. The Canadian/United States dollar exchange rate, which fluctuates over time, consequently affects the price received by Canadian producers of oil and natural gas. Material increases in the value of the Canadian dollar relative to the United States dollar will negatively affect the Corporation's production revenues. Accordingly, exchange rates between Canada and the United States could affect the future value of the Corporation's reserves as determined by independent evaluators. Although a low value of the Canadian dollar relative to the United States dollar may positively affect the price the Corporation receives for its oil and natural gas production, it could also result in an increase in the price for certain goods used for the Corporation's operations, which may have a negative impact on the Corporation's financial results.

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

Many central banks including the Bank of Canada have recently significantly raised interest rates in an attempt to combat inflation. Increasing interest rates results in a significant increase in the amount the Corporation pays to service debt, which depending on the amount of the Corporation's debt could result in a reduced amount available to fund its exploration and development activities and the cash available for dividends. In addition, increases in interest rates will impact the Corporation's ability to use debt financing to fund capital expenditures and acquisitions thereby potentially decreasing the Corporation's ability to carry out such activities, which could impact the future growth and sustainability of the Corporation's operations. Such an increase could also negatively impact the market price of the Common Shares.

Cost of New Technologies

The Corporation's ability to successfully implement new technologies into its operations in a timely and efficient manner will affect its ability to compete

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

Alternatives to and Changing Demand for Petroleum Products

Changes to the demand for oil and natural gas products and the rise of petroleum alternatives may negatively affect the Corporation's financial condition, results of operations and cash flow

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and renewable energy generation systems could reduce the demand for oil, natural gas and liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels and encourage the use of renewable fuel alternatives, which may lessen the demand for petroleum products and put downward pressure on commodity prices. Advancements in energy efficient products have a similar effect on the demand for oil and natural gas products. The Corporation cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Corporation's business, financial condition, results of operations and cash flow by decreasing the Corporation's profitability, increasing its costs, limiting its access to capital and decreasing the value of its assets.

Regulatory

Modification to current or implementation of additional regulations may reduce the demand for oil and natural gas and/or increase the Corporation's costs and/or delay planned operations

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing, transportation, infrastructure and mergers and acquisitions). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties, the exportation of oil and natural gas, infrastructure projects and the transfer of assets pursuant to acquisition and divestiture activities. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions.

The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for oil and natural gas and increase the Corporation's costs, either of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, obtaining certain approvals from regulatory authorities can involve, among other things, stakeholder and Indigenous consultation, environmental impact assessments, and public hearings. Regulatory approvals obtained may be subject to the satisfaction of certain conditions including, but not limited to: security deposit obligations; ongoing regulatory oversight of projects; mitigating or avoiding project impacts; environmental and habitat assessments; and other commitments or obligations. Further, the ongoing third-party challenges to regulatory decisions or orders have reduced the efficiency of the regulatory regime, as the implementation of the decisions and orders has been delayed resulting in uncertainty and interruption to the business of the oil and natural gas industry. See *"Industry Conditions – Regulatory Authorities and Environmental Regulation*".

In order to conduct oil and natural gas operations, the Corporation will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities at the municipal, provincial and federal level. There can be no assurance that the Corporation will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake. In addition, certain federal legislation such as the *Competition Act* and the *Investment Canada Act* could negatively affect the Corporation's business, financial condition and the market value of its Common Shares or its assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management*".

Royalty Regimes

Changes to royalty regimes may negatively impact the Corporation's cash flows

There can be no assurance that the governments in the jurisdictions in which the Corporation has assets will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of the Corporation's projects. An increase in royalties would reduce the Corporation's earnings and could make future capital investments, or the Corporation's operations, less economic. See "*Industry Conditions - Royalties and Incentives*".

Environmental

Compliance with environmental regulations requires the dedication of a portion of the Corporation's financial and operational resources

All phases of the crude oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, the initiation and approval of new oil and natural gas projects, restrictions and prohibitions on the spill, release or emission of various substances produced in association with oil and natural gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. New environmental legislation at the federal and provincial levels may increase uncertainty among oil and natural gas industry participants as the new laws are implemented, and the effects of the new rules and standards are felt in the crude oil and natural gas industry. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*".

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental legislation, no assurance can be given that environmental compliance requirements will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Liability Management

Liability management programs enacted by regulators in the western provinces may prevent or interfere with the Corporation's ability to acquire properties or require a substantial cash deposit with the regulator

Alberta, British Columbia and Saskatchewan have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its regulatory obligations. Changes to the AB LMR Program administered by the AER are currently underway. In July 2020, the Government of Alberta announced that the AB LMR and associated programs will be replaced by the AB LMF. Other changes to the requirements of liability management programs, may result in significant increases to the Corporation's compliance obligations. The impact and consequences of the Supreme Court of Canada's decision in Redwater on the AER's rules and policies, lending practices in the crude oil and natural gas sector and on the nature and determination of secured lenders to take enforcement proceedings are expected to evolve as the consequences of the decision are evaluated and considered by regulators, lenders and receivers/trustees. As a result of the decision, the Government of Alberta implemented the *Liabilities Management Statutes and Amendment Act*, which places the financial burden of a defunct licensee's abandonment and reclamation obligations on the working interest partners of the defunct Licensee and may order the AER's Orphan Fund to assume custody of wells or sites without a responsible owner to expedite the cleanup process.

In addition, the AB LMF Program may prevent or interfere with the Corporation's ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and natural gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. This is of particular concern to junior oil and natural gas companies that may be disproportionately affected by price instability. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs*".

Climate Change

Climate change concerns could result in increased operating costs and reduced demand for the Corporation's products and shares, while the potential physical effects of climate change could disrupt the Corporation's production and cause it to incur significant costs in preparing for or responding to those effects.

Global climate issues continue to attract public and scientific attention. Numerous reports, including reports from the Intergovernmental Panel on Climate Change, have engendered concern about the impacts of human activity, especially hydrocarbon combustion, on global climate issues. In turn, increasing public, government, and investor attention is being paid to global climate issues and to emissions of GHG, including emissions of carbon dioxide and methane from the production and use of oil, liquids and natural gas. The majority of countries across the globe, including Canada, have agreed to reduce their carbon emissions in accordance with the Paris Agreement. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*" for a summary of Canada's subsequent actions and pledges aimed at reducing Canada's GHG emissions and environmental impact. As discussed below, the Corporation faces both transition risks and physical risks associated with climate change and climate change policy and regulations.

Transition risks

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

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

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

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

Physical risks

Based on the Corporation's current understanding, the potential physical risks resulting from climate change are long-term in nature and associated with a high degree of uncertainty regarding timing, scope, and severity of potential impacts. Many experts believe global climate change could increase extreme variability in weather patterns such as increased frequency of severe weather, rising mean temperature and sea levels, and long-term changes in precipitation patterns. Extreme hot and cold weather, heavy snowfall, heavy rainfall, and wildfires may restrict the Corporation's ability to access its properties and cause operational difficulties, including damage to equipment and infrastructure. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions. Certain of the Corporation's assets are located in locations that are proximate to forests and rivers and a wildfire or flood may lead to significant downtime and/or damage to the Corporation's assets or cause disruptions to the production and transport of its products or the delivery of goods and services in its supply chain.

Natural Disasters, Terrorist Acts, Civil Unrest, Pandemics and Other Disruptions and Dislocations

Natural Disasters, Terrorist Acts, Civil Unrest, Pandemics and Other Disruptions and Dislocations, such as the recent COVID-19 (coronavirus), may adversely affect the Corporation

Upon the occurrence of a natural disaster, or upon an incident of war, riot or civil unrest, the impacted country, province, state or region may not efficiently and quickly recover from such event, which could have a materially adverse effect on the Corporation, its customers, and/or either of their businesses or operations. Terrorist attacks, public health crises including epidemics, pandemics or outbreaks of new infectious disease or viruses including, most recently, the COVID-19 outbreak, domestic and global trade disruptions, infrastructure disruptions, civil disobedience or unrest (including the most recent protests and railway blockades in Canada), natural disasters, national emergencies, acts of war, technological attacks and related events can result in volatility and disruption to local and global supply chains, operations, mobility of people and the financial markets, which could affect interest rates, credit ratings, credit risk, inflation, business, financial conditions, results of operations and other factors relevant to the Corporation, its customers, and/or either of their businesses or operations, which may have a material adverse effect on the Corporation's reputation, business, financial conditions or operating results.

Substantial Capital Requirements

The Corporation's access to capital may be limited or restricted as a result of factors related and unrelated to it, impacting its ability to conduct future operations, and acquire and develop reserves

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

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

Further, if the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. The conditions in, or affecting, the crude oil and natural gas industry have negatively impacted the ability of oil and natural gas companies, including the Corporation, to access additional financing and/or the cost thereof. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The Corporation may be required to seek additional equity financing on terms that are highly dilutive to existing shareholders. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

Additional Funding Requirements

The Corporation may require additional financing from time to time to fund the acquisition, exploration and development of properties and its ability to obtain such financing in a timely fashion and on acceptable terms may be negatively impacted by the current economic and global market volatility

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and, from time to time, the Corporation may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. Failure to obtain financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce its operations. Due to the conditions in the crude oil and natural gas industry and/or global economic and political volatility, the Corporation may, from time to time, have restricted access to capital and increased borrowing costs. The current conditions in the crude oil and natural gas industry have negatively impacted the ability of oil and natural gas companies to access, or the cost of, additional financing.

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

Asset Concentration

The Corporation's operations and drilling activity is vulnerable to risks associated with operating in a limited geographic area

The Corporation's producing properties are geographically concentrated. As a result, to the extent demand for and costs of personnel, equipment, power, services, and resources in such geographic area are high it could result in a delay or inability to secure the personnel, equipment, power, services, and resources. Any delay or inability to secure the personnel, equipment, power, services, and resources could result in crude oil, liquids and natural gas production volumes being below the Corporation's forecasted production volumes. In addition, any such negative effect on production volumes, or significant increases in costs, could have a material adverse effect on the Corporation's financial conditions, results of operations, cash flow, and profitability.

As a result of this concentration, the Corporation may be disproportionately exposed to the impact of delays or interruptions of operations or production in this area caused by external factors such as governmental regulation, provincial politics, market limitations, supply shortages, or extreme weather-related conditions.

Credit Facility Arrangements

Failing to comply with covenants under the Corporation's Credit Facility could result in restricted access to additional capital or being required to repay all amounts owing thereunder

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

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

Issuance of Debt

Increased debt levels may impair the Corporation's ability to borrow additional capital on a timely basis to fund opportunities as they arise

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

Hedging

Hedging activities expose the Corporation to the risk of financial loss and counter-party risk

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

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

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

Title to and Right to Produce from Assets

Defects in the title or rights to produce the Corporation's properties may result in a financial loss

The Corporation's actual title to and interest in its properties, and its right to produce and sell the crude oil and natural gas therefrom, may vary from the Corporation's records. In addition, there may be valid legal challenges or legislative changes that affect the Corporation's title to and right to produce from its oil and natural gas properties, which could impair the Corporation's activities and result in a reduction of the revenue received by the Corporation.

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

Reserves Estimates

The Corporation's estimated reserves are based on numerous factors and assumptions which may prove incorrect and which may affect the Corporation

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

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

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

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

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

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

Insurance

Not all risks of conducting oil and natural gas opportunities are insurable and the occurrence of an uninsurable event may have a materially adverse effect on the Corporation

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

The Corporation's insurance policies are generally renewed on an annual basis and, depending on factors such as market conditions, the premiums, policy limits and/or deductibles for certain insurance policies can vary substantially. In some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. Significantly increased costs could lead the Corporation to decide to reduce or possibly eliminate, coverage. In addition, insurance is purchased from a number of third-party insurers, often in layered insurance arrangements, some of whom may discontinue providing insurance coverage for their own policy or strategic reasons. Should any of these insurers refuse to continue to provide insurance coverage, the Corporation's overall risk exposure could be increased and the Corporation could incur significant costs.

Non-Governmental Organizations

The Corporation's properties may be subject to action by non-governmental organizations or terrorist attack

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

Dilution

The Corporation may issue additional Common Shares, diluting current shareholders

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

Management of Growth

The Corporation may not be able to effectively manage the growth of its business

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

Expiration of Licenses and Leases

The Corporation, or its working interest partners, may fail to meet the requirements of a licence or lease, causing its termination or expiry

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

Litigation

The Corporation may be involved in litigation in the course of its normal operations and the outcome of the litigation may adversely affect the Corporation and its reputation

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

Indigenous Land and Rights Claims

Opposition by Indigenous groups to the conduct of the Corporation's operations, development or exploratory activities may negatively impact the Corporation

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

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

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

In addition, Canada is a signatory to the United Nations Declaration on 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 November 2019, the *Declaration on the Rights of Indigenous Peoples Act* ("**DRIPA**") became law in British Columbia. The DRIPA aims to align British Columbia's laws with UNDRIP. In June 2021, the *United Nations Declaration on the Rights of Indigenous Peoples Act* ("**UNDRIP Act**") came into force in Canada. Similar to British Columbia's DRIPA, the UNDRIP Act requires the Government of Canada to take all measures necessary to ensure the laws of Canada are consistent with the principles of UNDRIP and to implement an action plan to address UNDRIP's objectives. 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 the DRIPA and the UNDRIP Act are expected to continue to add uncertainty to the ability of entities operating in the Canadian oil and gas industry to execute on major resource development and infrastructure projects, including, among other projects, pipelines. See "*Industry Conditions – Indigenous Rights*".

Breach of Confidentiality

Breach of confidentiality by a third party could impact the Corporation's competitive advantage or put it at risk of litigation

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

Income Taxes

Taxation authorities may reassess the Corporation's tax returns

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

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

Seasonality

Oil and natural gas operations are subject to seasonal weather conditions and the Corporation may experience significant operational delays as a result

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Extreme cold conditions during winter months at times can cause freeze-up and operational issues on both oil and gas wells. Wet weather and spring thaw may make the ground unstable which prevents, delays or makes operations more difficult. Consequently, municipalities and provincial transportation departments may enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Road bans and other restrictions generally result in a reduction of drilling and exploratory activities and may also result in the shut-in of some of the Corporation's production if not otherwise tied-in. Certain of the Corporation's oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of impassable muskeg.

Third Party Credit Risk

The Corporation is exposed to credit risk of third party operators or partners of properties in which it has an interest

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In addition, the Corporation may be exposed to third party credit risk from operators of properties in which the Corporation has a working or royalty interest. In the event such entities fail to meet their contractual obligations to the Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry, generally, and of the Corporation's joint venture partners may affect a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner. To the extent that any of such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in the Corporation being unable to collect all or a portion of any money owing from such parties. Any of these factors could materially adversely affect the Corporation's financial and operational results.

Information Technology Systems and Cyber-Security

Breaches of the Corporation's cyber-security and loss of, or access to, electronic data may adversely impact the Corporation's operations and financial position

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

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

Increasingly, social media is used as a vehicle to carry out cyber phishing attacks. Information posted on social media sites, for business or personal purposes, may be used by attackers to gain entry into the Corporation's systems and obtain confidential information. As social media continues to grow in influence and access to social media platforms becomes increasingly prevalent, there are significant risks that the Corporation may not be able to properly regulate social media use and preserve adequate records of business activities and client communications conducted through the use of social media platforms.

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

Conflicts of Interest

Conflicts of interest may arise for the Corporation's directors and officers who are also involved with other industry participants

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

Expansion into New Activities

Expanding the Corporation's business exposes it to new risks and uncertainties

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

Forward-Looking Information

Forward-looking information may prove inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on the Corporation's forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown 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.

Hydraulic Fracturing

Implementation of new regulations on hydraulic fracturing may lead to operational delays, increased costs and/or decreased production volumes, adversely affecting the Corporation's financial position

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

Alberta

Minor earthquakes are common in certain parts of Alberta, and are generally clustered around the municipalities of Cardston, Fox Creek, and Rocky Mountain House. Due to notable seismic activity reported around Fox Creek, the AER introduced seismic monitoring and reporting requirements for hydraulic fracturing operators in the Duvernay formation in the Fox Creek area in February 2015. These requirements include, among others, an assessment of the potential for seismicity prior to conducting operations, the implementation of a response plan to address potential seismic events, and the suspension of operations if a seismic event above a particular threshold occurs. These requirements remain in effect as long as the AER deems them necessary. In recent years, hydraulic fracturing has been linked to increased seismicity in the areas in which hydraulic fracturing takes place, leading to continued monitoring by the AER. The AER may extend seismic protocols to other areas of the province if necessary.

British Columbia

In 2018, the Government of British Columbia commissioned an independent scientific review panel to analyze hydraulic fracturing in the province and determine, among other things, how British Columbia's regulatory framework can be improved to better manage safety and environmental risks resulting from hydraulic fracturing operations. The implementation of new regulations or modification of existing regulations, in response to the panel's findings, may adversely affect the Corporation's business operations, financial condition, results of operations and prospects.

See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – British Columbia*".

The Government of British Columbia has come under increased scrutiny for its enforcement of environmental assessment, safety and licensing requirements for dams companies have built in association with their hydraulic fracturing operations. These requirements are outlined in provincial legislation, namely the *Water Sustainability Act* and the *Dam Safety Regulation*. Despite these regulatory requirements, reports have surfaced indicating that a number of unlicensed dams throughout northeastern British Columbia have been constructed without the requisite regulatory authorization. The BC Commission has issued compliance orders with respect to individual dams, but it remains uncertain how, and to what extent the relevant industry regulators will respond to this issue. The Corporation may face operational delays depending on the level of severity with which the overseeing regulatory authorities decide to address these unauthorized projects, particularly where the Corporation is not strictly complying with the current regulatory framework.

Waterflood

Regulatory water use restrictions and/or limited access to water or other fluids may impact the Corporation's production volumes from its waterflood

The Corporation undertakes or intends to undertake certain waterflooding programs which involve the injection of water or other liquids into an oil reservoir to increase production from the reservoir and to decrease production declines. To undertake such waterflooding activities the Corporation needs to have access to sufficient volumes of water, or other liquids, to pump into the reservoir to increase the pressure in the reservoir. There is no certainty that the Corporation will have access to the required volumes of water. In addition, in certain areas there may be restrictions on water use for activities such as waterflooding. If the Corporation is unable to access such water it may not be able to undertake waterflooding activities, which may reduce the amount of oil and natural gas that the Corporation is ultimately able to produce from its reservoirs. In addition, the Corporation may undertake certain waterflood programs that ultimately prove unsuccessful in increasing production from the reservoir and as a result have a negative impact on the Corporation's results of operations.

Additional information on the risks, assumptions and uncertainties are found under the heading "*Reader Advisory Regarding Forward-Looking Statements*" of this Annual Information Form.

Competition

The Corporation competes with other oil and natural gas companies, some of which have greater financial and operational resources

The petroleum industry is competitive in all of its phases. The Corporation competes with numerous other entities in the exploration, development, production and marketing of oil and natural gas. The Corporation's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. Some of these companies not only explore for, develop and produce oil and natural gas, but also carry on refining operations and market oil and natural gas on an international basis. As a result of these complementary activities, some of these competitors may have greater and more diverse competitive resources to draw on than the Corporation. The Corporation's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price, process, and reliability of delivery and storage.

Changing Investor Sentiment

Changing investor sentiment towards the crude oil and natural gas industry may impact the Corporation's access to, and cost of, capital

A number of factors, including the effects of the use of fossil fuels on climate change, the impact of oil and natural gas operations on the environment, environmental damage relating to spills of petroleum products during production and transportation and Indigenous rights, have affected certain investors' sentiments towards investing in the crude oil and natural gas industry. As a result of these concerns, some institutional, retail and governmental investors have announced that they no longer are willing to fund or invest in oil and natural gas properties or companies, or are reducing the amount thereof over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices. Developing and implementing such policies and practices can involve significant costs and require a significant time commitment from the Board, management and employees of the Corporation. 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 crude oil and natural 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 Corporation's securities even if the Corporation's operating results, underlying asset values or prospects have not changed.

Reputational Risk Associated with the Corporation's Operations

The Corporation relies on its reputation to continue its operations and to attract and retain investors and employees

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

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

Diluent Supply

A decrease in, or restriction in access to, diluent supply may increase the Corporation's operating costs

Heavy crude oil and bitumen are characterized by high specific gravity or weight and high viscosity or resistance to flow. Diluent is required to facilitate the transportation of heavy crude oil and bitumen. A shortfall in the supply of diluent, or a restriction in access to diluent, may cause its price to increase, increasing the cost to transport heavy crude oil and bitumen to market. An increase to the cost of bringing heavy crude oil and bitumen to market may increase the Corporation's overall operating cost and result in decreased net revenues, negatively impacting the overall profitability of the Corporation's heavy crude oil and bitumen projects.

ADDITIONAL INFORMATION

Additional information relating to Gear may be found on SEDAR at www.sedar.com.

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Gear's securities and securities authorized for issuance under equity compensation plans is contained in Gear's management information circular relating to the Corporation's most recent annual meeting of shareholders that involved the election of directors.

Additional information is also provided in Gear's financial statements and management's discussion and analysis for the year ended December 31, 2022, which documents may be found on SEDAR at www.sedar.com.

SCHEDULE "A"

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

To the board of directors of Gear Energy Ltd. (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 board of directors:

			Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – M$)			
Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Audited	Evaluated	Reviewed	**Total**
Sproule Associates Limited	December 31, 2022	Canada	Nil	473,744	Nil	473,744

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, 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 reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.

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

EXECUTED as to our report referred to above:

Sproule Associates Limited, Calgary, Alberta, Canada, February 23, 2023.

(Signed) "Gary R. Finnis"

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

SCHEDULE "B"

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

Management of Gear Energy Ltd. (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.

An independent qualified reserves evaluator has evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluator is presented in Schedule "A" to this Annual Information Form.

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 evaluator;

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

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

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

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

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

(c) the content and filing of this report.

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

Per: (signed) "*Ingram Gillmore*"
Ingram Gillmore
President, Chief Executive Officer and Director

Per: (signed) "*Bryan Dozzi*"
Bryan Dozzi
Vice President, Engineering

Per: (signed) "*Donald T. Gray*"
Donald T. Gray
Director

Per: (signed) "*Scott Robinson*"
Scott Robinson
Director

March 24, 2023

SCHEDULE "C"

GEAR ENERGY LTD.

AUDIT COMMITTEE

MANDATE AND TERMS OF REFERENCE

ROLE AND OBJECTIVE

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of Gear Energy Ltd. ("**Gear**" or the "**Corporation**") to which the Board has delegated its responsibility for the oversight of the following:

1. nature and scope of the annual audit;
2. the oversight of management's reporting on internal accounting standards and practices;
3. the review of financial information, accounting systems and procedures;
4. financial reporting and financial statements,

and has charged the Committee with the responsibility of recommending, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information.

The primary objectives of the Committee are as follows:

1. To assist the Board in meeting its responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of the Corporation and related matters;
2. To provide better communication between directors and external auditors;
3. To enhance the external auditor's independence;
4. To increase the credibility and objectivity of financial reports; and
5. To strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management of Gear ("**Management**") and external auditors.

Membership of Committee

1. The Committee will be comprised of at least three (3) directors or such greater number as the Board may determine from time to time and all members of the Committee shall be "independent" (as such term is used in National Instrument 52-110 – Audit Committees ("**NI 52-110**")) unless the Board determines that the exemption contained in NI 52-110 is available and determines to rely thereon.
2. The Board may from time to time designate one of the members of the Committee to be the Chair of the Committee.
3. All of the members of the Committee must be "financially literate" unless the Board determines that an exemption under NI 52-110 from such requirement in respect of any particular member is available and determines to rely thereon in accordance with the provisions of NI 52-110.
4. For the purposes of this Mandate, "financially literate" has the meaning ascribed thereto in NI 52-110 and means that the member has the ability to read and understand a set of financial statements that present a breadth and level of

complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Corporation's financial statements.

Mandate and Responsibilities of Committee

It is the responsibility of the Committee to:

1. Oversee the work of the external auditors, including the resolution of any disagreements between Management and the external auditors regarding financial reporting;

2. Satisfy itself on behalf of the Board with respect to Gear's internal control systems identifying, monitoring and mitigating business risks; and ensuring compliance with legal, ethical and regulatory requirements;

3. Review the annual and interim financial statements of the Corporation and related management's discussion and analysis ("**MD&A**") prior to their submission to the Board for approval. The process may include but not be limited to:

    (a) reviewing changes in accounting principles and policies, or in their application, which may have a material impact on the current or future years' financial statements;

    (b) reviewing significant accruals, reserves or other estimates such as ceiling test calculation;

    (c) reviewing accounting treatment of unusual or non-recurring transactions;

    (d) ascertaining compliance with covenants under loan agreements;

    (e) reviewing disclosure requirements for commitments and contingencies;

    (f) reviewing adjustments raised by the external auditors, whether or not included in the financial statements;

    (g) reviewing unresolved differences between Management and the external auditors; and

    (h) obtain explanations of significant variances with comparative reporting periods;

4. Review the financial statements, prospectuses, MD&A, annual information forms ("**AIF**") and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of Gear's disclosure of other financial information and must periodically assess the adequacy of those procedures;

5. With respect to the appointment of external auditors by the Board:

    (a) recommend to the Board the external auditors to be nominated;

    (b) recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors will report directly to the Committee;

    (c) on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with the Corporation to determine the auditors' independence;

    (d) when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change;

(e) review and pre-approve any non-audit services to be provided to Gear or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. The Committee may delegate to one or more independent members the authority to pre–approve non–audit services, provided that the member(s) report to the Committee at the next scheduled meeting such pre–approval and the member(s) comply with such other procedures as may be established by the Committee from time to time;

6. Review with external auditors (and internal auditor if one is appointed by Gear) their assessment of the internal controls of Gear, their written reports containing recommendations for improvement, and Management's response and follow-up to any identified weaknesses. The Committee will also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Gear and its subsidiaries;

7. Review risk management policies and procedures of the Corporation (i.e., hedging, litigation and insurance);

8. To review and satisfy itself on behalf of the Board that management has adequate procedures in place for reporting and certification under the *Extractive Sector Transparency Measures Act* (Canada) ("**ESTMA**") when the Corporation is required to comply with ESTMA;

9. To review the non-GAAP financial measures, non-GAAP ratios, capital management measures and supplementary financial measures (as each of such terms is defined in National Instrument 52-112 - *Non-GAAP and Other Financial Measures* ("**NI 52-112**")) used by the Corporation in public disclosure documents to ensure that (i) such measures and ratios are appropriate and not misleading in light of the Corporation's business, and (ii) procedures are in place for ensuring that disclosure of such measures complies with NI 52-112 and any other applicable securities legislation;

10. Establish a procedure for:

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

    (b) the confidential, anonymous submission by employees of Gear of concerns regarding questionable accounting or auditing matters; and

11. Review and approve Gear's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of the Corporation.

The Committee has authority to communicate directly with the internal auditors (if any) and the external auditors of the Corporation. The Committee will also have the authority to investigate any financial activity of Gear. All employees of Gear are to cooperate as requested by the Committee.

Meetings and Administrative Matters

1. At all meetings of the Committee every resolution shall be decided by a majority of the votes cast. In case of an equality of votes, the Chair of the meeting shall not be entitled to a second or casting vote.

2. The Chair will preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee that are present will designate from among such members the Chair for purposes of the meeting.

3. A quorum for meetings of the Committee will be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee will be the same as those governing the Board unless otherwise determined by the Committee or the Board.

4. Meetings of the Committee should be scheduled to take place at least four times per year and at such other times as the Chair of the Committee or any two members of the Committee may determine. Minutes of all meetings of the Committee will be taken. The Chief Financial Officer of Gear will attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chair.

5. Any two directors may request the Chair to call a meeting of the Committee and may attend at such meeting or inform the Committee of a specific matter of concern to such directors, and may participate in such meeting to the extent permitted by the Chair of the Committee.

6. The Committee will meet with the external auditor in camera at least once per year (in connection with the preparation of the year-end financial statements) and at such other times as the external auditor and the Committee consider appropriate.

7. Agendas, approved by the Chair, will be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.

8. The Committee may invite such officers, directors and employees of the Corporation and its subsidiaries as it sees fit from time to time to attend at meetings of the Committee and assist in the discussion and consideration of the matters being considered by the Committee.

9. Minutes of the Committee will be recorded and maintained and circulated to directors who are not members of the Committee or otherwise made available at a subsequent meeting of the Board.

10. The Committee may retain special legal, accounting, financial or other consultants or advisors to advise the Committee at the Corporation's expense and shall have sole authority to retain and terminate any such consultants or advisors and to approve any such consultant's or advisor's fees and retention terms.

11. The Committee may delegate from time to time any person or committee of persons any of the Committee's responsibilities that lawfully may be delegated.

12. The Committee will conduct meetings "in-camera", without management, as deemed appropriate by the Committee.

13. Any members of the Committee may be removed or replaced at any time by the Board and will cease to be a member of the Committee as soon as such member ceases to be a director. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy exists on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, following appointment as a member of the Committee each member will hold such office until the Committee is reconstituted.

14. Any issues arising from these meetings that bear on the relationship between the Board and Management should be communicated to the Chair of the Board by the Committee Chair.

15. Nothing contained in this mandate is intended to expand applicable standards of liability under statutory, regulatory, common law or any other legal requirements for the Board or members of the Committee. The Committee may adopt additional policies and procedures as it deems necessary from time to time to fulfill its responsibilities.

November 3, 2021