



**ANNUAL INFORMATION FORM**

for the year ended December 31, 2020

**March 22, 2021**

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SCHEDULE "A" -	FORM 51-101F2 – REPORT ON RESERVES DATA BY INDEPENDENT RESERVES EVALUATORS
SCHEDULE "B" -	FORM 51-101F3 – REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE
SCHEDULE "C" -	AUDIT COMMITTEE MANDATE AND TERMS OF REFERENCE

## ABBREVIATIONS

### Crude Oil and Natural Gas Liquids

bbf	one barrel
Bbl	barrels
bbf/d	barrels per day
Mbbl	thousand barrels
BOE	barrels of oil equivalent of natural gas on the basis of 1 BOE for 6 Mcf of natural gas (unless otherwise indicated)
MBOE	one thousand barrels of oil equivalent
MMBOE	one million barrels of oil equivalent
BOE/d	barrels of oil equivalent per day
NGL	natural gas liquids
Stb	standard stock tank barrel

### Natural Gas

Mcf	one thousand cubic feet
Mcfe	one thousand cubic feet of natural gas equivalent on the basis of 6 Mcfe for 1 bbl of oil (unless otherwise indicated)
MMcf	one million cubic feet
Bcf	one billion cubic feet
Mcf/d	one thousand cubic feet per day
MMcf/d	one million cubic feet per day
GJ	gigajoule
GJs/d	gigajoules per day
Btu	British thermal unit
MMbtu	million British thermal units

**BOEs or Mcfe may be misleading, particularly if used in isolation. A BOE or Mcfe conversion ratio of six Mcfe 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 Mcfe:1 bbl, utilizing a conversion on a 6 Mcfe: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 <sup>3</sup>	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 (" <b>10<sup>3</sup>m<sup>3</sup></b> ")	0.0282
thousand cubic metres	Mcf	35.494
bbl	cubic metres (" <b>m<sup>3</sup></b> ")	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;

"**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;

"**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;

"**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 \$50 million credit facilities with a syndicate of lenders led by ATB Financial (formerly Alberta Treasury Branches) entered into by Gear on July 27, 2016 concurrently with the completion of the Striker Arrangement, as amended and increased by a first amending agreement made as of November 30, 2016, a second amending agreement made as of May 25, 2017, a third amending agreement made as of May 4, 2018, a fourth amending agreement made as of September 18, 2018 increasing the borrowing base to \$115 million concurrently with the completion of the Steppe Arrangement, a fifth amending agreement made as of May 23, 2019 decreasing the borrowing base to \$90 million, a sixth amending agreement dated September 3, 2019, a seventh amending agreement dated May 28, 2020, and as amended and decreased to \$75 million by an amended and restated credit agreement made as of July 10, 2020, which provided for a further three mandatory repayments and corresponding reductions of the borrowing base scheduled for September 30, 2020, December 31, 2020, and March 31, 2021 of \$5 million each, as amended by a first amending agreement dated August 31, 2020, a waiver and second amending agreement dated September 29, 2020, a third amending agreement dated November 30, 2020 and a fourth amending agreement dated December 18, 2020;

"**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, 2019*";

"**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](http://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, 2020 and dated February 3, 2021;

"**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<sup>th</sup> 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, 2020.

## 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 for 2021, 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, 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 public health risks including COVID-19, including, but not limited to, any restrictions on Gear's operations resulting from COVID-19 and any destruction in oil and gas demand resulting from COVID-19, 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 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 for 2021; the Corporation's potential drilling locations and budget for 2021 if commodity prices change, upwards or downwards, in a material fashion; 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 – 5<sup>th</sup> Avenue S.W., Calgary, Alberta T2P 2V7 and its registered office is located at Suite 2400, 525 – 8<sup>th</sup> 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, 2018***

On May 31, 2018, Ms. Bindu Wyma was appointed to the Board and to the Reserves Committee of the Board.

On May 4, 2018, the borrowing base under the Credit Facilities was increased to \$75 million.

On September 18, 2018, Gear completed the Steppe Arrangement whereby the Corporation acquired all of the issued and outstanding common shares of Steppe pursuant to a plan of arrangement under the ABCA. Shareholders of Steppe received 0.1445 of a Common Share for each share of Steppe owned, resulting in the issuance of 21.9 million Common Shares by Gear. Gear also assumed Steppe's net debt of approximately \$40.9 million, after taking into account Steppe's transaction costs.

Pursuant to the Steppe Arrangement, Steppe amalgamated with 2138359 Alberta Ltd., a wholly-owned subsidiary of Gear, and continued under the name "Steppe Resources Inc." Immediately following the amalgamation, Gear amalgamated with the newly formed Steppe Resources Inc., now a wholly-owned subsidiary of Gear, and continued under the name "Gear Energy Ltd."

Concurrent with the completion of the Steppe Arrangement, Gear entered into an amending agreement in respect of the Credit Facilities, providing for an increase in the borrowing base to \$115 million. Steppe's senior secured credit facility was repaid in full and terminated in connection with the closing of the Steppe Arrangement.

Total capital spending in 2018, including net acquisitions, was \$110 million. Aside from the Steppe Arrangement, the majority of these funds were spent to drill 26 Gross (24 Net) horizontal oil wells with a 96% success rate. The 2018 drilling program focused on multiple areas including Wildmere, Wilson Creek, Paradise Hill and Hoosier.

#### ***Year Ended December 31, 2019***

On May 8, 2019, Mr. Raymond Cej retired from the Board.

On May 23, 2019, the borrowing base of the Credit Facilities was reduced from \$115 million to \$90 million. Following the reduction of the borrowing base, the Credit Facilities were comprised of a \$70 million syndicated revolving term credit facility and a \$20 million operating credit facility.

On July 9, 2019, the Corporation announced that Mr. John O'Connell resigned from the Board and Mr. Scott Robinson was appointed to the Board.

On August 7, 2019, the Corporation announced that Mr. Kevin Olson retired from the Board and Messrs. Greg Bay and Wilson Wang were appointed to the Board.

On August 7, 2019, the Corporation announced its intention to proceed with 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. In order to effect the NCIB, Gear was required to reduce its stated capital pursuant to the provisions of the ABCA. At a special meeting of Gear's shareholders held on September 20, 2019, the shareholders of the Corporation approved a special resolution to reduce the stated capital of the Common Shares by \$150 million to \$90 million. See "*Description of Capital Structure – Reduction in Stated Capital*".

The TSX approved the NCIB on September 23, 2019. The NCIB commenced on September 25, 2019 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) September 24, 2020, unless terminated earlier at the option of the Corporation upon prior notice being given to the TSX. Pursuant to the NCIB, Gear was able to purchase for cancellation up to 10,954,673 Common Shares (approximately 5% 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 was permitted to purchase was subject to a daily purchase limit of 58,069 Common Shares (representing 25% of the average daily trading volume of 232,278 Common Shares on the TSX calculated for the six-month period ended August 31, 2019); however, Gear could make one block purchase per calendar week that exceeded the daily purchase restrictions. 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. For the period ended December 31, 2019, 1.6 million Common Shares with an aggregate value of \$0.7 million were repurchased pursuant to the NCIB.

On November 27, 2019, the Corporation completed its semi-annual borrowing base review and no further changes were made to the Credit Facilities.

Total capital spending in 2019, including net acquisitions, was \$36.0 million. The majority of these funds were spent to drill 16 Gross (16 Net) oil wells with a 100% success rate. The 2019 drilling program focused on multiple areas including Wildmere, Maidstone, Tableland and Wilson Creek.

#### ***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 the NCIB.

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.

### **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 December of 2020, the Board approved a \$20 million capital budget for 2021, targeting stabilized production and continued improvement of its strong balance sheet. Gear expects its 2022 capital program to be financed with funds from operations. Under the approved capital budget for 2021, \$15.8 million of the budgeted capital is intended to be dedicated to drilling 18 (17.5 Net) drilling locations, including 14 Lloydminster area heavy crude oil wells, 3 Provost medium crude oil wells and 1.0 (0.5 Net) southeast Saskatchewan light oil well; \$2.0 million of budgeted capital is intended to be invested in continued waterflood expansions, recompletions, workovers and field facility projects; \$1.1 million is intended to be invested in ongoing abandonment and reclamation activities (with an additional \$4.8 million of abandonment and reclamation activities to be funded by the Canadian federal government funding); and \$1.1 million of budgeted capital is intended to be invested towards land, seismic and other corporate costs.

The amount and allocation of capital the Corporation will expend for its 2021 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 2021 exploration and development program. Although Gear's management remains committed to the above strategy, the uncertainty resulting from COVID, the current instability and uncertainty in the Canadian crude oil and natural gas industry and the challenges crude oil and natural gas producers continue to face with respect to the availability of funds and access to markets 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 2020, Gear invested approximately \$0.9 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. During 2020, Gear utilized \$0.6 million from the program to extinguish liabilities by conducting abandonment and reclamation activities. 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 – Climate Change 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 2020, Gear spent approximately \$0.5 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 – Climate Change 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 2020, 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 2021 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, 2020, Gear had 28 employees with 17 staff in the Calgary office and 11 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 3, 2021. The effective date of the Statement is December 31, 2020 and the preparation date of the Statement is February 3, 2021.

### **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, 2020. 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 of Management and Directors on Oil and Gas Disclosure and the Report on Reserves Data by the Independent Qualified Reserves Evaluator 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, 2020  
FORECAST PRICES AND COSTS

RESERVES CATEGORY	RESERVES									
	LIGHT AND MEDIUM CRUDE OIL		HEAVY CRUDE OIL		CONVENTIONAL NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL	
	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mbbbl)	Net (Mbbbl)	Gross (MMcft)	Net (MMcft)	Gross (Mbbbl)	Net (Mbbbl)	Gross (MBOE)	Net (MBOE)
Proved Developed										
Producing	3,405.7	3,110.0	2,483.1	2,326.5	6,084	5,497	302.2	246.2	7205.1	6,598.7
Non-Producing	14.9	14.3	62.2	59.7	83	67	7.1	4.3	98	89.4
Proved										
Undeveloped	2,295.1	2,113.7	2,888.2	2,667.3	2,259	2,066	135.0	120.8	5,694.8	5,246.1
Total Proved	5,715.8	5,238.1	5,433.4	5,053.4	8,426	7,630	444.3	371.2	12,997.9	11,934.3
Probable	4,655.5	4,252.0	4,680.3	4,217.0	5,474	4,977	252.1	215.1	10,500.3	9,513.5
Total Proved plus Probable	10,371.2	9,490.1	10,113.8	9,270.5	13,900.0	12,605	696.4	586.4	23,498.2	21,447.8

NET PRESENT VALUES OF FUTURE NET REVENUE

RESERVES CATEGORY	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)					UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year (\$/BOE)
	0	5	10	15	20	0	5	10	15	20	
	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	
Proved Developed											
Producing	15,014	66,883	73,787	71,463	67,414	15,014	66,883	73,787	71,463	67,414	11.18
Non-Producing	485	567	588	579	556	485	567	588	579	556	6.58
Proved Undeveloped	72,508	50,035	34,940	24,579	17,247	72,508	50,035	34,940	24,579	17,247	6.66
Total Proved	88,007	117,485	109,315	96,621	85,216	88,007	117,485	109,315	96,621	85,216	9.16
Probable	196,526	150,593	110,950	84,401	66,223	196,526	150,593	110,950	84,401	66,223	11.66
Total Proved plus Probable	284,533	268,079	220,265	181,022	151,439	284,533	268,079	220,265	181,022	151,439	10.27



TOTAL FUTURE NET REVENUE  
(UNDISCOUNTED)  
AS OF DECEMBER 31, 2020  
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M\$)	ROYALTIES (M\$)	OPERATING COSTS (M\$)	DEVELOPMENT COSTS (M\$)	ABANDONMENT AND RECLAMATION COSTS <sup>(1)</sup> (M\$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M\$)	INCOME TAXES (M\$)	FUTURE NET REVENUE AFTER INCOME TAXES (M\$)
Total Proved	662,236	58,195	271,125	110,221	134,688	88,007	-	88,007
Total Proved plus Probable	1,245,273	116,179	468,141	219,854	156,566	284,533	-	284,533

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, 2020  
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 <sup>(1)</sup>	67,630	\$10.33/boe
	Heavy Crude Oil <sup>(1)</sup>	41,759	\$8.18/boe
	Conventional Natural Gas <sup>(2)</sup>	(74)	\$(0.26)/boe
Proved Plus Probable Reserves	Light Crude Oil and Medium Crude Oil <sup>(1)</sup>	118,623	\$10.17/boe
	Heavy Crude Oil <sup>(1)</sup>	101,371	\$10.81/boe
	Conventional Natural Gas <sup>(2)</sup>	271	\$0.67/boe

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) Columns may not add due to rounding.

**Notes to Reserves Data Tables:**

- Columns may not add due to rounding.
- 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.
- 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, 2020, which are as follows:

#### SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS FORECAST PRICES AND COSTS

Year	OIL			Natural Gas AB Plant Gate Spot Gas Price	Pentanes Plus Edmonton	Butanes Price Edmonton	Inflation Rates <sup>(1)</sup>	Exchange Rate <sup>(2)</sup>
	WTI Cushing Oklahoma	Edmonton Oil Price 40° API	WCS Oil Price					
	(\$US/bbl)	(\$Cdn/bbl)	(\$Cdn/bbl)	(\$Cdn/MMBtu)	(\$Cdn/bbl)	(\$Cdn/bbl)	%/Year	(\$US/\$Cdn)
Forecast								
2021	47.17	55.76	44.63	2.78	59.24	26.36	0.00	0.77
2022	50.17	59.89	48.18	2.70	63.19	32.85	1.33	0.77
2023	53.17	63.84	52.10	2.61	67.34	39.20	2.00	0.76
2024	54.97	65.76	54.10	2.65	69.77	40.65	2.00	0.76
2025	56.07	67.13	55.19	2.70	71.18	41.50	2.00	0.76
2026	57.19	68.53	56.29	2.76	72.61	42.36	2.00	0.76
2027	58.34	69.95	57.42	2.81	74.07	43.24	2.00	0.76
2028	59.50	71.40	58.57	2.87	75.56	44.14	2.00	0.76
2029	60.69	72.88	59.74	2.92	77.08	45.06	2.00	0.76
2030	61.91	74.34	60.93	2.98	78.62	45.96	2.00	0.76
2031+	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, 2020 were \$2.24/Mcf for natural gas, \$45.41/bbl for light and medium oil, \$32.64/bbl for heavy crude oil and \$19.56/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

FACTORS	LIGHT AND MEDIUM CRUDE OIL			HEAVY CRUDE OIL			NATURAL GAS LIQUIDS		
	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)
<b>December 31, 2019<sup>(1)</sup></b>	<u>6,882</u>	<u>4,360</u>	<u>11,242</u>	<u>6,906</u>	<u>5,800</u>	<u>12,705</u>	<u>705</u>	<u>329</u>	<u>1,033</u>
Discoveries	-	-	-	-	-	-	-	-	-
Extensions	183	169	307	328	253	497	2	1	2
Infill Drilling	16	-	-	-	-	-	2	-	-
Improved Recovery	43	28	72	-	-	-	1	-	1
Technical Revisions	516	(428)	149	47	(762)	(632)	(142)	(94)	(232)
Acquisitions	12	4	16	-	-	-	1	1	2
Dispositions	(26)	(10)	(35)	(109)	(212)	(322)	(4)	(1)	(5)
Economic Factors	(1,361)	532	(829)	(646)	(398)	(1,043)	(59)	16	(42)
Production	(551)	-	(551)	(1,092)	-	(1,092)	(62)	-	(62)
<b>December 31, 2020<sup>(2)</sup></b>	<u>5,716</u>	<u>4,655</u>	<u>10,371</u>	<u>5,433</u>	<u>4,680</u>	<u>10,113</u>	<u>444</u>	<u>252</u>	<u>696</u>

FACTORS	CONVENTIONAL NATURAL GAS			TOTAL		
	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (MBOE)	Gross Probable (MBOE)	Gross Proved Plus Probable (MBOE)
<b>December 31, 2019<sup>(1)</sup></b>	<b>10,540</b>	<b>4,661</b>	<b>15,201</b>	<b>16,249</b>	<b>11,265</b>	<b>27,515</b>
Discoveries	-	-	-	-	-	-
Extensions	216	122	212	549	444	841
Infill Drilling	19	-	-	21	-	-
Improved Recovery	41	21	62	51	32	83
Technical Revisions	378	97	620	485	(1,268)	(611)
Acquisitions	16	6	22	16	6	22
Dispositions	(27)	(10)	(36)	(143)	(225)	(368)
Economic Factors	(1,363)	577	(786)	(2,292)	246	(2,046)
Production	(1,394)	-	(1,394)	(1,938)	-	(1,938)
<b>December 31, 2020<sup>(2)</sup></b>	<b>8,427</b>	<b>5,474</b>	<b>13,901</b>	<b>12,998</b>	<b>10,500</b>	<b>23,498</b>

Notes:

- (1) The opening balance as at December 31, 2019 was derived from an independent engineering evaluation of Gear's oil, natural gas liquids and natural gas interests prepared by Sproule effective December 31, 2019 and dated February 4, 2020.
- (2) Columns may not add due to rounding.

Both proved and proved plus probable reserves under economic factors were negatively impacted by a weaker 2020 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 plus probable reserves was continued conservatism on the view of future production profiles for both developed and undeveloped locations, the removal of legacy undeveloped locations and finally the removal of drill locations on expired mineral acreage in heavy oil and Saskatchewan light oil.

#### **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, 2020, 2019 and 2018.

Proved Undeveloped Reserves

Year	Light and Medium Crude Oil (Mbbbl)		Heavy Crude Oil (Mbbbl)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbbl)		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
2018	2,063	3,268	528	3,175	829	3,779	50	191	2,780	7,264
2019	145	2,970	368	3,465	115	3,713	9	242	541	7,295
2020	105	2,295	203	2,888	177	2,259	4	135	341	5,694

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 (Mbbbl)		Heavy Crude Oil (Mbbbl)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbbl)		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
2018	2,227	2,972	1,045	4,541	621	2,330	32	146	3,408	8,047
2019	445	2,923	425	4,178	132	2,279	8	156	900	7,637
2020	80	3,253	135	3,525	(44)	3,043	(3)	139	205	7,423

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 reserves are identified, they are included in Gear's development plans. Normally, the Corporation plans to develop its proved and probable undeveloped reserves within two to three years; however, 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, 2020 and the accompanying management's discussion and analysis, which are available on SEDAR at [www.sedar.com](http://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:

Year	Forecast Capital Costs (M\$)	
	Proved Reserves	Proved Plus Probable Reserves
2021	13,545	18,499
2022	26,498	65,623
2023	29,915	61,212
2024	27,858	46,675
2025	12,405	19,659
Thereafter	-	8,186
Total Undiscounted	110,221	219,854

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, 2020 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 7,700 Gross (7,500 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 Celtic/Paradise Hill area. The plan for 2021 includes the drilling of ten Gross (10 Net) horizontal heavy crude McLaren oil wells. See "*Description of the Business – Business Plan and Corporate Strategy*".

The Sproule Report assigns total proved plus probable reserves of 3,919 Mbbls of heavy crude oil at December 31, 2020 within the Celtic area.

The average production from the area for in 2020 was 1,210 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 27,000 Gross (25,000 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 GP 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 GP and Sparky formations. In 2020, Gear did not drill any wells in the area. The plan for 2021 includes drilling two Gross (2 Net) General Petroleum and one Gross (1 Net) Sparky multi-lateral heavy crude horizontal oil wells in the Wildmere area. See "*Description of the Business – Business Plan and Corporate Strategy*".

The Sproule Report assigns total proved plus probable reserves of 3,126 Mbbls of heavy crude oil and 0.69 Bcf of natural gas as at December 31, 2020 within the Wildmere area. The average production from the area in 2020 was 1,211 BOE/d, which consisted of 1,139 bbls/d of heavy crude oil and 436 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 54,000 Gross (42,000 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 light oil wells. In 2019, Gear drilled one Gross (1 Net) horizontal light oil well in the Wilson Creek area. In 2020, Gear did not drill any wells in the area. The plan for 2021 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 3,246 Mbbls of light crude oil and NGLs and 5.95 Bcf of natural gas as at December 31, 2020 within Wilson Creek.

The average production from the area in 2020 was 700 BOE/d, which consisted of 378 bbls/d of light and medium crude oil, 1,230 mcf/d of conventional natural gas and 117 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 35,000 Gross (34,000 Net) acres of land. There are no material expiries expected as the majority of lands have been continued pursuant to the applicable tenure regulations.

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 1,400 to 1,700 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. The associated gas from the Tableland production is currently flared, although various options for conservation are being 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. The plan for 2021 is to drill one Gross (0.5 Net) non-operated light crude Torquay horizontal oil well in the Tableland area. 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 4,977 Mbbls of light crude oil and NGLs as at December 31, 2020 within Tableland.

The average production from the area for in 2020 was 616 BOE/d all of which consisted of light and medium crude oil.

#### *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, 2020. In 2017, Gear drilled three heavy crude oil wells in Hoosier, Saskatchewan, and two medium oil wells in Killam, Alberta. In 2018, Gear drilled two heavy crude oil wells in Hoosier, Saskatchewan, one heavy crude oil well in Lindbergh, Alberta and one 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. The plan for 2021 includes drilling three Gross (3 Net) multi-lateral medium crude horizontal oil wells in the Provost area and one Gross (1 Net) multi-lateral heavy crude horizontal oil well in the Swimming area. See "*Description of the Business – Business Plan and Corporate Strategy*".

The Sproule Report assigns total proved plus probable reserves of 5,914 Mbbls of light, medium and heavy crude oil and NGLs and 7.26 Bcf of natural gas as at December 31, 2020 within these other areas.

The average production from these areas in 2020 was 1,559 BOE/d, which consisted of 512 bbls/d of light and medium crude oil, 635 bbls/d of heavy crude oil, 2,149 mcf/d of conventional natural gas and 54 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 in which the Corporation had a working interest as at December 31, 2020.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	343	281	655	612	402	59	204	163
British Columbia	-	-	-	-	-	-	6	1
Saskatchewan	145	143	162	148	1	1	43	40
Total	488	424	817	760	403	60	253	204

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, 2020.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	135,083	107,363	74,210	66,921	209,293	174,284
British Columbia	4,057	3,706	3,413	3,062	7,470	6,768
Saskatchewan	56,342	52,602	31,640	31,233	87,982	83,835
<b>Total</b>	<b>195,482</b>	<b>163,671</b>	<b>109,263</b>	<b>101,216</b>	<b>304,745</b>	<b>264,887</b>

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 11,658 net acres of its undeveloped land holdings that may expire by December 31, 2021, 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, 2020, in respect of the hedging activities is included in Note 10 to Gear's audited financial statements for the year ended December 31, 2020, which are available on SEDAR at [www.sedar.com](http://www.sedar.com).

***Tax Horizon***

Based on current forward commodity prices, the Corporation does not expect to pay current income tax for the 2021 fiscal year. Gear does not expect to pay income tax in the next 5 years. There are multiple factors which impact the tax horizon of the Corporation, the most notable being production, commodity prices and capital spending levels. Despite current tax pools exceeding the book value of property, plant and equipment Gear currently does not recognize a deferred tax asset but has recognized a deferred tax asset in the past.

**Capital Expenditures**

The following table summarizes capital expenditures related to the Corporation's activities for the year ended December 31, 2020:

	(M\$)
Corporate Acquisition Cost	-
Property Acquisition Costs	
Proved properties	203
Undeveloped properties	-
Exploration costs	213
Development costs	12,228
Dispositions	(200)
Total	<u>12,444</u>

**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, 2020:

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Light and Medium Crude Oil	-	-	2	2
Heavy Crude Oil	-	-	7	7
Conventional Natural Gas	-	-	-	-
Dry	-	-	-	-
Service/Other	-	-	-	-
Stratigraphic Test	-	-	-	-
Total	<u>-</u>	<u>-</u>	<u>9</u>	<u>-</u>

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 2021 in the estimates of future net revenue from Gross proved and Gross probable reserves disclosed under "Disclosure of Reserves Data".

<b>From Gross Proved Reserves:</b>	Light and Medium Crude Oil	Heavy Crude Oil	Conventional Natural Gas	Natural Gas Liquids	BOE	%
	(bbls/d)	(bbls/d)	(Mcf/d)	(bbls/d)	(BOE/d)	
Wildmere	-	932	233	-	970	19
Celtic	-	1,362	-	-	1,362	27
Wilson Creek	386	-	1,107	96	667	13
Tableland	695	-	-	-	695	13
Other	528	576	1,713	41	1,431	28
<b>Total</b>	<b>1,609</b>	<b>2,870</b>	<b>3,053</b>	<b>137</b>	<b>5,125</b>	<b>100</b>

Note:

(1) Columns may not add due to rounding.

<b>From Gross Probable Reserves:</b>	Light and Medium Crude Oil	Heavy Crude Oil	Conventional Natural Gas	Natural Gas Liquids	BOE	%
	(bbls/d)	(bbls/d)	(Mcf/d)	(bbls/d)	(BOE/d)	
Wildmere	-	93	17	-	96	11
Celtic	-	384	-	-	384	44
Wilson Creek	24	-	47	4	36	4
Tableland	36	-	-	-	36	4
Other	165	119	243	3	327	37
<b>Total</b>	<b>225</b>	<b>596</b>	<b>307</b>	<b>7</b>	<b>879</b>	<b>100</b>

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:

	2020			
	Dec. 31	Sept. 30	June 30	Mar. 31
<b>Average Daily Production<sup>(1)</sup></b>				
Light and Medium Crude Oil (bbls/d) <sup>(2)</sup>	1,657	1,746	845	1,775
Heavy Crude Oil (bbls/d) <sup>(2)</sup>	3,236	3,321	1,388	3,989
Conventional Natural Gas (Mcf/d) <sup>(3)</sup>	4,477	3,761	2,474	4,582
NGLs (bbls/d)	182	174	103	217
Combined (BOE/d)	5,821	4,761	2,749	6,744
<b>Average Price Received</b>				
Light and Medium Crude Oil (\$/bbl) <sup>(2)</sup>	48.10	47.61	24.91	50.44
Heavy Crude Oil (\$/bbl) <sup>(2)</sup>	36.16	40.27	20.46	27.58
Conventional Natural Gas (\$/Mcf) <sup>(3)</sup>	2.69	2.25	1.98	1.93
NGLs (\$/bbl)	26.02	20.30	25.73	10.54
Combined (\$/BOE)	36.68	39.00	20.74	31.24
<b>Royalties Paid</b>				
Light and Medium Crude Oil (\$/bbl) <sup>(2)</sup>	4.09	3.52	2.13	4.53
Heavy Crude Oil (\$/bbl) <sup>(2)</sup>	4.83	4.21	0.73	3.59
Conventional Natural Gas (\$/Mcf) <sup>(3)</sup>	0.41	0.02	0.26	0.40
NGLs (\$/bbl)	6.77	1.20	3.13	2.50
Combined (\$/BOE)	4.38	3.48	1.38	3.66
<b>Operating Expenses (\$/BOE)</b>				
Light and Medium Crude Oil (\$/bbl) <sup>(2)</sup>	16.26	15.94	14.33	17.96
Heavy Crude Oil (\$/bbl) <sup>(2)</sup>	17.16	16.29	16.69	18.07
Conventional Natural Gas (\$/Mcf) <sup>(3)</sup>	2.99	3.06	3.65	3.30
NGLs (\$/bbl)	10.31	13.31	8.34	10.86
Combined (\$/BOE)	16.79	16.31	16.43	18.01
<b>Netback Received (\$/BOE)<sup>(4)</sup></b>				
Light and Medium Crude Oil (\$/bbl) <sup>(2)</sup>	27.75	28.14	8.45	27.96
Heavy Crude Oil (\$/bbl) <sup>(2)</sup>	14.17	19.77	3.04	5.92
Conventional Natural Gas (\$/Mcf) <sup>(3)</sup>	(0.71)	(0.83)	(1.93)	(1.76)
NGLs (\$/bbl)	8.93	5.79	14.26	(2.82)
Combined (\$/BOE)	15.51	19.21	2.93	9.57

## 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, 2020:

	Light and Medium Crude Oil <sup>(1)</sup> (bbls/d)	Heavy Crude Oil <sup>(1)</sup> (bbls/d)	Conventional Natural Gas <sup>(2)</sup> (Mcf/d)	NGLs (bbls/d)	BOE (BOE/d)
Celtic	-	1,198	-	-	1,198
Wildmere	-	1,139	430	-	1,211
Wilson Creek	379	-	1,321	124	723
Tableland	616	-	-	-	616
Other	512	648	2,074	45	1,551
Total	1,507	2,985	3,825	169	5,298

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, 2020 was 56% heavy crude oil, 28% light and medium oil, 12% natural gas and 3% was NGLs. For the year ended December 31, 2020, 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**

The Corporation has never declared or paid any cash dividends on the Common Shares. The Corporation currently intends to retain future earnings, if any, for future operations, expansion and debt repayment. Any decision to declare and pay dividends will be made at the discretion of the Board and will depend on, among other things, the Corporation's results of operations, current and anticipated cash requirements and surplus, financial condition, contractual restrictions and financing agreement covenants, solvency tests imposed by corporate law and other factors that the Board may deem relevant.

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) if declaring or paying the dividend would result in a default under the Credit Facilities; or (ii) during the continuance of a borrowing base shortfall, which is the amount by which the aggregate of all outstanding obligations under the Credit Facilities exceeds the then current borrowing base of the Credit Facilities as a result of a reduction or redetermination of the borrowing base (until cured).

#### **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 217,992,966 Common Shares and no Series 1 Preferred Shares are currently issued and outstanding. Additionally, the Corporation has \$12.7 million aggregate principal amount of Convertible Debentures outstanding. An aggregate of 39.7 million additional Common Shares may be issued on conversion of the Convertible Debentures that remain outstanding at the date hereof. The following is a summary description of the rights, privileges, restrictions and conditions attaching to the Common Shares, the Preferred Shares, the Series 1 Preferred Shares and the Convertible Debentures.

#### **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.

### **Convertible Debentures**

On November 30, 2020, the Corporation entered into the Amended and Restated Convertible Debenture Indenture, which amended and restated the Original Convertible Debenture Indenture. A copy of the Amended and Restated Convertible Debenture Indenture is available for review on [www.sedar.com](http://www.sedar.com). Under the terms of the Amended and Restated Convertible Debenture Indenture, the Convertible Debentures have a maturity date of November 30, 2023 and carry a coupon of 7.00% per annum payable semi-annually in arrears on November 30th and May 31st until maturity. Gear may pay interest in-kind on the Convertible Debentures for the period from December 1, 2020 to November 30, 2021 by issuing additional Convertible Debentures to the holders of the Convertible Debentures. Each \$1,000 principal amount of Convertible Debentures is convertible at the option of the holder at any time prior to the maturity date of the Convertible Debentures at a conversion price of \$0.32 per Common Share. Holders converting their Convertible Debentures are entitled to receive accrued and unpaid interest thereon for the period from the date of the latest interest payment date to, but excluding, the date of conversion. The Convertible Debentures are also redeemable by the Corporation at any time by fully repaying the principal amount and all accrued interest owing on the Convertible Debentures on the date selected for redemption. There is presently \$12.7 million in Convertible Debentures outstanding.

In certain circumstances, the Corporation has the option to satisfy its obligation to repay the principal amount of the Convertible Debentures due at maturity or redemption of the Convertible Debentures by the issuance of Common Shares and the number of such Common Shares will be based on 95% of the weighted average trading price of the Common Shares prior to the date fixed for maturity or redemption.

The Convertible Debentures are direct, subordinated unsecured obligations of the Corporation and rank equally with one another and with all other existing and future subordinated unsecured indebtedness of the Corporation. The conversion price of the Convertible Debentures is subject to standard anti-dilution adjustments as set forth in the Convertible Debenture Indenture.

## 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, 2020:

Period	Price Range (\$)		Trading Volume
	High	Low	
<b>2020</b>			
January	0.50	0.37	4,494,903
February	0.41	0.25	3,680,806
March	0.325	0.08	25,841,423
April	0.255	0.09	12,667,441
May	0.26	0.17	2,883,784
June	0.28	0.185	4,266,084
July	0.215	0.165	2,355,508
August	0.24	0.155	3,818,669
September	0.20	0.135	3,285,907
October	0.175	0.15	1,331,661
November	0.27	0.15	4,006,494
December	0.31	0.21	4,159,330
<b>2021</b>			
January	0.315	0.25	3,145,742
February	0.43	0.25	8,947,101
March (1 - 22)	0.54	0.36	18,019,401

### Prior Sales

The following table sets forth the securities of the Corporation issued during the year ended December 31, 2020 that are not listed on the TSX (or any other stock exchange):

Date	Number of Securities	Issue Price Per Security <sup>(1)</sup> (\$)	Type of Security
March 2, 2020	318,000	0.29	Options
May 19, 2020	1,422,000	0.20	Options
August 17, 2020	495,000	0.23	Options
November 16, 2020	3,618,000	0.18	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:



<u>Name, Province and Country of Residence</u>	<u>Position(s) with Gear</u>	<u>Principal Occupation During the Five Years Preceding</u>
Greg Bay <sup>(1)(3)</sup> 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 <sup>(1)(3)</sup> 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. (" <b>ARC</b> ")
Don T. Gray <sup>(1)(2)(3)</sup> 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) (" <b>Peyto</b> ") 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 <sup>(2)(3)</sup> 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 <sup>(1)(3)</sup> 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 <sup>(2)(3)</sup> 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.
Yvan Chretien Alberta, Canada	Vice President, Land since September 2010	Vice President, Land of Gear since September 2010; prior thereto, Vice-President, Land at ARC from 2006 to March 2010.
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

<u>Name, Province and Country of Residence</u>	<u>Position(s) with Gear</u>	<u>Principal Occupation During the Five Years Preceding</u>
Edward (Ted) Brown Alberta, Canada	Corporate Secretary since August 2015	2014 to October 2016 and geologist at Gear from October 2010 to April 2014.  Partner 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 Compensation and Governance 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 19,581,605 Common Shares constituting approximately 8.98% of the issued and outstanding Common Shares.

### **Cease Trade Orders, Bankruptcies, Penalties or Sanctions**

#### ***Cease Trade Orders***

Other than as disclosed below, 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, 2020, 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, 2020, 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 Computershare Trust Company of Canada at its principal offices in Calgary, Alberta and Toronto, Ontario.

## **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, other than the Convertible Debenture Indenture (see "*Description of Capital Structure – Convertible Debentures*"), which is available on [www.sedar.com](http://www.sedar.com).

## 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 Alberta, Canada	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.

<u>Name, Province and Country of Residence</u>	<u>Independent</u>	<u>Financially Literate</u>	<u>Relevant Education and Experience</u>
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. Mr. Bay holds a director position with the Mullen Group Ltd.
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:

<u>Year</u>	<u>Audit Fees<sup>(1)</sup></u>	<u>Audit -Related Fees<sup>(2)</sup></u>	<u>Tax Fees</u>	<u>All Other Fees<sup>(3)</sup></u>
	(\$)	(\$)	(\$)	(\$)
2020	186,715	6,420	-	5,164
2019	193,670	-	-	102,225

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 2020 and 2019 these amounts relate to consulting fees paid to Deloitte LLP for Gear's regulatory, safety and environmental program.

## INDUSTRY CONDITIONS

Companies operating in the 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; and 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 may be enacted.

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; (ii) technical drilling and well requirements; (iii) permitted locations and access of 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.

Outlined below are 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 crude oil. Worldwide supply and demand factors are the primary determinant of crude oil prices; however, regional market and transportation issues also influence prices. The specific price depends, in part, on crude oil quality, prices of competing products, distance to market, availability of transportation, value of refined products, supply/demand balance and contractual terms of sale.

Since early 2020, worldwide oversupply of oil, a lack of available storage capacity and decreased demand due to COVID-19 have had a significant impact on the price of oil. In an effort to stabilize global oil markets, OPEC and a number of other oil producing countries announced an agreement to cut oil production by approximately 10 million bbls/d in April 2020. This agreement contributed to rebalancing global oil markets by achieving approximately 99.5% compliance with the agreed production adjustment commitments. However, economic recovery has slowed due to a resurgence of COVID-19 in major economies.

#### *Natural Gas*

Negotiations between buyers and sellers determines the price of natural gas sold in intra-provincial, interprovincial and international trade. The price received by a natural gas producer depends, in part, on the price of competing natural gas supplies and other fuels, natural gas quality, distance to market, availability of transportation, length of contract term, weather conditions, supply/demand balance and other contractual terms of sale.

#### *Natural Gas Liquids*

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* (Canada) (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**

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

#### *Pipelines*

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

Under the Canadian Constitution, 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.

#### *Specific Pipeline Updates*

The Enbridge Line 3 Replacement from Hardisty, Alberta, to Superior, Wisconsin, previously expected to be in-service in late 2019, has faced significant delays due to permitting difficulties in the United States. However, Minnesota regulators approved the final required permit for the project in November 2020. Certain segments of the Line 3 Replacement in North Dakota and Wisconsin are currently in operation and the Canadian portion of the replaced pipeline began commercial operation in December 2019. Construction of the Line 3 Replacement in Minnesota began in early December 2020; Enbridge expects the line to be in service in the fourth quarter of 2021.

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 and it is expected to be in-service in December 2022.

On March 31, 2020, TC Energy Corporation ("**TC Energy**") announced it would proceed with the Keystone XL Pipeline. TC Energy also announced that the Government of Alberta had made a US \$1.1 billion equity investment in the project and would guarantee a US \$4.2 billion project level credit facility. While construction on the Keystone XL Pipeline started in April 2020,

the project remains subject to legal and regulatory barriers in the United States, including the cancellation of a presidential permit on January 20, 2021 that permits the Keystone XL Pipeline to operate across the international border.

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, potentially forcing the lines comprising this segment of the pipeline system to be shut down by May 2021. Enbridge filed a federal complaint in late November 2020 in the United States District Court for the Western District of Michigan and is seeking an injunction to prevent the termination of the easement. Enbridge 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.

### *Marine Tankers*

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

### *Crude Oil and Bitumen by Rail*

In February 2020, following two train derailments that led to fires and oil spills in Saskatchewan, the federal government announced that trains hauling more than 20 cars carrying dangerous goods, including crude oil and diluted bitumen, would be subject to reduced speed limits. The order was updated in April 2020 and will remain in place until permanent rule changes are approved.

### *Natural Gas and LNG*

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

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. However, in September 2019, the CER approved a policy change by TC Energy on its NOVA Gas Transmission Ltd. pipeline system (the "**NGTL System**") to prioritize deliveries into storage (the "**Temporary Service Protocol**"). The change stabilized supply and pricing, particularly during periods of maintenance on the system, but, in February 2021, the CER refused a request to extend the Temporary Service Protocol. However, in October 2020, TC Energy received federal approval to expand the NGTL System and the expanded NGTL System is expected to be fully operational by 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**"). Pre-construction activities on the LNG Canada facility began in November 2018, with a completion target of 2025.

In late 2019, TC Energy announced that it would sell a 65% equity interest in the CGL Pipeline to investment companies KKR & Co Inc. and Alberta Investment Management Corporation while remaining the pipeline operator. The transaction closed in May 2020. Despite its 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.



In addition to LNG Canada and the CGL Pipeline projects, the following is an update on various other LNG Projects that have been proposed in Canada:

- In December 2019, the CER approved a 40-year export licence for the Kitimat LNG project, a proposed joint venture between Chevron Canada Limited and Woodside Energy International (Canada) Limited. However, both partners are looking to sell some or all of their interest in the project.
- Woodfibre LNG Limited, a subsidiary of Singapore-based Pacific Oil and Gas Ltd. has proposed to build the Woodfibre LNG Project, a small-scale LNG processing and export facility near Squamish, British Columbia. The BC Commission approved a project permit for the Woodfibre LNG Project in July 2019 and a formal approval of the project is expected in the third quarter of 2021, with construction beginning shortly thereafter.
- GNL Québec Inc., the proponent of the Énergie Saguenay Project, is currently working its way through a federal impact assessment process for the construction and operation of an LNG facility and export terminal located on Saguenay Fjord, an inlet which feeds into the St. Lawrence River in Québec. The Énergie Saguenay Project is currently slated for completion in 2026.
- Pieridae Energy Ltd.'s ("**Pieridae**") proposed Goldboro LNG project, located in Nova Scotia, would see LNG exported from Canada to European markets. Pieridae has agreements with Shell, upstream, and with Uniper, a German utility, downstream. The federal government has issued Goldboro LNG a 20-year export licence, but Pieridae has delayed its final investment decision until mid-2021.
- Finally, Cedar LNG Export Development Ltd.'s Cedar LNG Project near Kitimat, British Columbia, is currently in the environmental assessment stage, with British Columbia's Environmental Assessment Office (the "**BC EAO**") conducting the environmental assessment on behalf of the Impact Assessment Agency of Canada ("**IA Agency**").

### *Enbridge Open Season*

In August 2019, Enbridge initiated an open season for the Enbridge mainline system, which has historically operated as a common carrier oil pipeline system. A common carrier pipeline must accept all products offered to it for transportation. If there is insufficient capacity to transport the volumes offered, the available capacity is pro-rated to accommodate all shippers. The changes that Enbridge intends to implement include the transition of the mainline system from a common carrier to a primarily contract carrier pipeline, wherein shippers will have to commit to reserved space in the pipeline for a fixed term, with only 10% of available capacity reserved for nominations. If the service change is approved, shippers seeking firm capacity on the Enbridge system would no longer be able to rely on the nomination process and would have to enter long-term contracts for service.

Several shippers challenged Enbridge's open season and, in particular, Enbridge's ability to engage in an open season without first obtaining prior regulatory approval to implement a contract carriage model. Following an expedited hearing process, the CER decided to shut down the open season. On December 19, 2019, Enbridge applied to the CER for approval of the proposed service and tolling framework. The regulatory hearing process is currently underway and a final decision from the CER is not expected until mid-2021. If Enbridge receives CER approval, it intends to hold the open season by the end of 2021.

### **Curtailment**

In December 2018, the Government of Alberta announced that, commencing January 1, 2019, it would mandate a short-term reduction in provincial crude oil and crude bitumen production. As contemplated in the *Curtailment Rules*, the Government of Alberta, on a monthly basis, required oil and bitumen producers producing more than 20,000 bbls/d to limit their production according to a pre-determined formula that allocates production limits proportionately amongst all operators subject to curtailment orders.

Curtailment first took effect on January 1, 2019, limiting province-wide production of oil and bitumen. As of December 2020, monthly oil production limits are no longer in effect. However, the *Curtailment Rules*, which were set to be repealed on December 31, 2020, have been extended such that the Government of Alberta retains the ability to impose production limits if needed.

## 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, 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 have an impact on Western Canada's oil and gas industry at large, including the Corporation's business.

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

## Land Tenure

### *Mineral rights*

With the exception of Manitoba each provincial government in Western Canada owns most of the mineral rights to the crude oil and natural gas located within their respective provincial borders. Provincial governments grant rights to explore for and produce crude 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 governments of Alberta, British Columbia and Saskatchewan announced measures to extend or continue Crown leases that may have otherwise expired in the months following the implementation of pandemic response measures. In March 2020, the British Columbia Ministry of Energy, Mines and Petroleum Resources (now called the Ministry of Energy, Mines and Low Carbon Innovation) announced that it was suspending posting requests and leases of petroleum and natural gas rights until further notice due to COVID-19.

All of the provinces of Western Canada have all 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 crude oil and natural gas, private ownership of crude 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 ("**IOGC**") manages subsurface and surface leases in consultation with applicable Indigenous peoples, for the exploration and production of oil and natural gas on Indigenous reservations. Until recently, oil and natural gas activities conducted on Indian reserve lands were governed by the *Indian Oil and Gas Act* (the "**IOGA**") and the *Indian Oil and Gas Regulations, 1995* (the "**1995 Regulations**"). In 2009, Parliament passed *An Act to Amend the Indian Oil and Gas Act*, amending and modernizing the IOGA (the "**Modernized IOGA**"); however the amendments were delayed until the federal government was able to complete stakeholder consultations and update the accompanying Regulations (the "**2019 Regulations**"). The Modernized IOGA and the

2019 Regulations came into force on August 1, 2019 and further regulations are currently being developed. The Corporation does not have any material operations on Indian reserve lands.

### *Surface rights*

To develop crude 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.

## **Royalties and Incentives**

### *General*

Each province has legislation and regulations that 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 crude oil, natural gas and NGLs production. Royalties payable on production from lands where the Crown does not hold the mineral rights are determined by negotiation between the mineral freehold owner and the lessee, though certain provincial taxes and other charges on production or revenues may be payable.

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, the governments of Western Canada's provinces create incentive programs for the oil and gas industry. Such 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. In addition, such programs may be introduced to encourage producers to prioritize certain kinds of development or utilize technologies that may enhance or improve recovery of crude oil, natural gas and NGLs, or improve environmental performance.

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

### *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. The Mines and Minerals Act was amended in 2014 to shorten the window during which producers can submit amendments to their royalty calculations before they become statute-barred, from four years to three.

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 for a period of ten years ending on December 31, 2026. After the expiry of this ten-year period, these older wells will become subject to the Modernized Framework. The *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 for each well, depending on its vertical depth and/or horizontal length. The formula is based on the industry's average drilling and completion costs as determined by the Alberta Energy Regulator (the "AER") on an annual basis.

Under the Old Framework, royalty rates for conventional crude oil production can be as high as 40% of gross revenues and royalty rates for natural gas production can be as high as 36% of gross revenues. 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 crude 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 crude oil and natural gas are negotiated between the producer and the resource owner.

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.

#### *British Columbia*

##### *Crown royalties*

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 crude 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 up to 40%, based on factors such as the volume of crude oil produced from a particular well or unitized tract and the crude oil vintage. Royalty rates are reduced on certain wells, including low-productivity wells, 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 crude oil and natural gas are negotiated between the producer and the resource owner. In addition to these negotiated royalties, producers of crude 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 crude oil and natural gas in Saskatchewan are paid on a well-by-well basis. Producers of crude oil and natural gas receive royalty invoices from the Government on a monthly basis.

The Crown royalty rate payable in respect of crude oil is paid on a well-by-well basis and depends on a number of variables, including the type and vintage of crude oil, the quantity of crude oil produced in a given month, the average wellhead price and certain price adjustment factors. Based on these factors, the base royalty rate payable ranges from 5% to 20% and the marginal royalty rate payable from 25% to 45%. 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 of natural gas and the 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% to 20% and the marginal royalty rate ranges from 30% to 45%.

### *Freehold royalties and taxes*

Royalty rates for the production of privately owned crude oil and natural gas are negotiated between the producer and the resource owner. In addition, producers must pay a freehold production tax, determined by first 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 \$1.50 per acre 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 crude 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 Western Canadian crude oil and natural gas industry is currently 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 crude oil and natural 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 to future changes to environmental legislation, (typically measured in terms of their global warming potential and expressed in terms of carbon dioxide equivalent ("**CO<sub>2</sub>e**")), may impose further requirements on operators and other companies in the crude oil and natural gas industry.

### *Federal*

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

On August 28, 2019, with the passing of Bill C-69, the CERA and the *Impact Assessment Act* (the "**IAA**") came into force and replaced the *Canadian Environmental Assessment Act, 2012* ("**CEAA 2012**").

The enactment of the CERA and the IAA introduced a number of important changes to the regulatory regime for federally regulated major projects and associated environmental assessments. The CERA separates the CER's administrative and adjudicative functions. A board of directors and a chief executive officer manage strategic, administrative and policy considerations while adjudicative functions fall to independent commissioners. The CER jurisdiction over matters such as the environmental and economic regulation of pipelines, transmission infrastructure and certain offshore renewable energy projects, including offshore wind and tidal facilities. In its adjudicative role, the CERA tasks the CER with reviewing applications for the development, construction and operation of these projects, culminating in their eventual abandonment.

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

The federal government has stated that an objective of the legislative changes was to improve decision certainty and turnaround times. Once a review or assessment is commenced under either the CERA or IAA, there are limits on the amount of time the relevant regulatory authority will have to issue its report and recommendation. Designated projects will go through a planning phase to determine the scope of the impact assessment, which the federal government has stated should provide more certainty as to the length of the full review process. The Government of Alberta has submitted a reference question to the Alberta Court of Appeal regarding the constitutionality of the IAA and the hearing is expected to take place in the first half of 2021.

#### *Alberta*

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

The Government of Alberta relies on regional planning to accomplish its responsible 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 in Alberta 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.

#### *British Columbia*

In British Columbia, the *Oil and Gas Activities Act* (the "**OGAA**") regulates conventional crude oil and natural gas producers, shale gas producers and other operators of crude oil and natural gas facilities in the province. Under the OGAA, the British Columbia Oil and Gas Commission (the "**BC Commission**") has broad powers, particularly with respect to compliance and enforcement and the setting of technical safety and operational standards for crude oil and natural gas activities. The *Environmental Protection and Management Regulation* establishes the government's environmental objectives and requires the BC Commission to consider these environmental objectives in deciding whether or not to authorize a particular activity. In

addition, although not an exclusively environmental statute, 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.

An updated *Environmental Assessment Act* 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 British Columbia Government 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 BC EAO 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 crude 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* (the "**OGCR**") and *The Petroleum Registry and Electronic Documents Regulations* (the "**Registry 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 partner in the Petrinex Database.

### **Liability Management Rating Program**

#### *Alberta*

The AER administers the licensee Liability Management Rating Program (the "**AB LMR Program**"), which is currently undergoing changes, including a name change to the "Liability Management Framework" (the "**AB LMF**"). The AB LMR Program is a liability management program governing most conventional upstream crude oil and natural gas wells, facilities and pipelines. It consists of three distinct programs: the Licensee Liability Rating Program (the "**AB LLR Program**"), the Oilfield Waste Liability Program (the "**AB OWL Program**") and the Large Facility Liability Management Program (the "**AB LFP**"). If a licensee's deemed liabilities in the AB LLR Program, the AB OWL Program and/or the AB LFP exceed its deemed assets in those programs, the licensee must reduce its liabilities or provide the AER with a security deposit. Failure to do so may restrict the licensee's ability to transfer licences. This ratio of a licensee's assets to liabilities across the three programs is referred to as the licensee's liability management rating ("**LMR**").

The AER previously assessed the LMR of all licensees on a monthly basis and posted the individual ratings on the AER's public website. However, in December 2019 the AER ceased posting the detailed LMR report, stating that resource and budget limitations have impacted its ability to maintain and administer the AB LMR Program. Licensees can continue to access their individual LMR calculations through the AER's Digital Data Submission System, but they do not have access to other licensees' LMR. Any changes to the AB LMR Program may affect the Corporation's ability to obtain or transfer licences.

In July 2020, the Government of Alberta announced that the AB LMF will replace the AB LMR Program and its constituent programs. Among other changes under the AB LMF, the AB LMR Program will be replaced with the Licensee Capability Assessment System, which is intended to be a more comprehensive assessment of corporate health and will consider a wider variety of factors than those considered under the AB LMR Program and establish clear expectations for industry with regards to the management of liabilities throughout the entire lifecycle of oil and gas projects. Importantly, the AB LMF will also provide proactive support to distressed operators and will require mandatory annual minimum payments towards outstanding reclamation obligations in accordance with five-year rolling spending targets.

Complementing 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. The Orphan Fund was originally conceived to be bankrolled exclusively by Licensees in the AB LLR Program and AB OWL Program who

contribute to 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 LFP. 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.

In response to the increase in orphaned oil and gas sites and the environmental risks associated therewith, the AER amended its *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals*, which deals with licensee eligibility to operate wells and facilities, to require the provision of extensive corporate governance and shareholder information. All transfers of well, facility and pipeline licences in the province are subject to AER approval. As a condition of transferring existing AER licences, approvals and permits, all transfers are now assessed on a non-routine basis and the AER now requires all transferees to demonstrate that they have an LMR of 2.0 or higher immediately following the transfer, or to otherwise prove to the satisfaction of the AER that it can meet its abandonment and reclamation obligations.

As a result of the Supreme Court of Canada's decision in *Orphan Well Association v Grant Thornton* (also known as 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 will come into force on proclamation.

The Government of Alberta followed the announcement of the AB LMF with amendments to the *Oil and Gas Conservation Rules* and the *Pipeline Rules* in late 2020. The changes to these rules fall into three broad 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.

The AER has published a draft of an amended Directive 067 to implement some of these changes (the "**Draft Directive**"), and has issued a call for feedback on the Draft Directive that will be open until mid-February 2021. The changes introduced by the Draft Directive include building on the AER's corporate and financial disclosure requirements for parties who wish to acquire, hold or transfer licences in Alberta, and broadening the AER's discretion to withhold or revoke licensees' privileges if they are assessed as posing an "unreasonable risk". The feedback that the AER receives will be considered in the determination of the final revised Directive 067, and the rollout of the AB LMF may require changes to other Directives as well. As a result, the Corporation's ongoing and future transactions may be affected in this period of transition, resulting in processing delays for licence transfers and regulatory uncertainty as the criteria and requirements for licensees are subject to change.

To address abandonment and reclamation liabilities in Alberta, the AER implements, from time to time, programs intended to encourage the decommissioning, remediation and reclamation of inactive or marginal oil and natural gas infrastructure. Beginning in 2015, for example, the AER oversaw the Inactive Well Compliance Program, a five-year intended to address the growing inventory of inactive and noncompliant wells in Alberta. More recently, the AER announced a voluntary area-based closure ("**ABC**") program in 2018. The ABC program is designed to reduce the cost of abandonment and reclamation operations through industry collaboration and economies of scale. Parties seeking to participate in the program must commit to an inactive liability reduction target to be met through closure work of inactive assets.

#### *British Columbia*

Similar to Alberta, the BC Commission oversees a Liability Management Rating Program (the "**BC LMR Program**"), which is designed to manage public liability exposure related to crude oil and natural gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. Under the BC LMR Program, the BC Commission determines the required security deposits for permit holders under the OGAA. The liability



management rating is the ratio of a permit holder's deemed assets to deemed liabilities. Permit holders whose deemed liabilities exceed deemed assets (i.e., an LMR below 1.0) will be considered at-risk and reviewed for a security deposit. Permit holders that fail to comply with security deposit requirements are deemed non-compliant under the OGAA and enter the compliance and enforcement framework.

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 BC Commission to impose more than one levy in a given calendar year.

Effective May 31, 2019, 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 the well(s) on 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 BC Commission, 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 an annual work plan.

### *Saskatchewan*

The Saskatchewan Ministry of Energy and Resources administers the Licensee Liability Rating Program (the "**SK LLR Program**"). The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to the orphan fund (the "**Oil and Gas Orphan Fund**") established under the SKOGCA. The Oil and Gas Orphan Fund is responsible for 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. On August 19, 2016, the Saskatchewan Ministry of the Economy released a notice to all operators introducing interim measures in response to Redwater. Among other things, the Saskatchewan Ministry of the Economy announced that it considers all licence transfer applications non-routine as it does not strictly rely on the standard LLR calculation in evaluating deposit requirements. In addition to increased security deposit requirements, the Saskatchewan Ministry of the Economy at that time announced in 2016 that it may incorporate additional conditions with licence transfer approvals.

### *Federal and Provincial Support for Liability Management*

As part of an announcement of federal relief for Canada's oil and gas industry in response to COVID-19, the federal government pledged \$1.72 billion to clean up orphan and inactive wells in Alberta, Saskatchewan and British Columbia. However, these funds are being administered by regulatory authorities in each province. In Alberta, the Ministry of Energy is disbursing its \$1 billion share of the federally provided funds through the Site Rehabilitation Program. In addition to the funds administered by the respective provincial governments, the federal government announced a \$200 million loan to Alberta's Orphan Fund. The Government of British Columbia is disbursing its \$120 million share of the federally provided funds through three programs: the Dormant Sites Reclamation Program, the Orphan Sites Supplemental Reclamation Program and the Legacy Sites Reclamation Program. In Saskatchewan, \$400 million in federal funding will be allocated through the Accelerated Site Closure Program ("**ASCP**"). The first phase of the ASCP will make \$100 million available to eligible service companies to conduct abandonment and reclamation work. Further tranches of the ASCP, up to \$300 million, will be made available in the future.

### *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 crude oil and natural gas industry in Canada. These impacts are uncertain. It is currently not possible to predict the extent of 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. Decisions about a prospective carbon market and emissions cuts until the next climate conference, scheduled to take place in November 2021.

The Government of Canada has pledged to cut its emissions by 30% from 2005 levels by 2030, but indicated in its recent Speech from the Throne (also referred to as the "**Throne Speech**"; discussed in greater detail below) that it may implement policy changes to exceed this target. Specific details have not yet been announced.

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 for large industry and a regulatory fuel charge imposing an initial price of \$20/tonne of CO<sub>2</sub>e emissions. This system applies in provinces and territories that request it and in those that do not have their own emissions pricing systems in place that meet the federal standards. This ensures that there is a uniform price on emissions across the country. Under current federal plans, this price will escalate by \$10 per year until it reaches a price of \$50/tonne of CO<sub>2</sub>e in 2022. On December 11, 2020, however, the federal government announced its intention to continue the annual price increases beyond 2022, such that, commencing in 2023, the benchmark price per tonne of CO<sub>2</sub>e will increase by \$15 per year until it reaches \$170/tonne of CO<sub>2</sub>e in 2030. Starting April 1, 2021, the minimum price permissible under the GGPPA is \$40/tonne of CO<sub>2</sub>e.

Alberta, Saskatchewan, and Ontario have referred the constitutionality of the GGPPA to their respective Courts of Appeal. In both the Saskatchewan and Ontario references, the appellate Courts ruled in favour of the constitutionality of the GGPPA; the Alberta Court of Appeal determined that the GGPPA is unconstitutional. All three judgments have been appealed to the Supreme Court of Canada. The hearing took place in September 2020, but the Court has not yet released its decision.

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 crude 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 intentional venting of methane, as well as ensuring that crude oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and natural gas facilities are permitted to vent. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

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

As part of its efforts to provide relief to Canada's oil and gas industry in light of the COVID-19 pandemic, the federal government announced a \$750 million Emissions Reduction Fund intended to support pollution reduction initiatives, including methane. Funds disbursed through this program will primarily take the form of repayable contributions to onshore and offshore oil and gas firms.

The federal government has also announced that it will implement a Clean Fuel Standard that will require producers, importers and distributors to reduce the emissions intensity of liquid fuels. It is expected that the applicable regulations will come into force in December 2022.

In the September 23, 2020 Throne Speech, the federal government has indicated that it intends to make a number of investments that will help it achieve net-zero emissions by 2050, including investments intended to: (i) improve transit options; (ii) make zero-emissions vehicles more affordable; (iii) expand electric vehicle charging infrastructure across the country; (iv) launch a fund that will help attract investments in the development of zero-emissions technology, including a corporate tax cut of 50%

for companies participating in this initiative; (v) develop a Clean Power Fund that will, in part, help regions transition to cleaner sources of power generation; and (vi) support continued investment in the development and implementation of renewable and clean energy technologies. Specific program details have not yet been announced.

On November 19, 2020, the federal government introduced the *Canadian Net-Zero Emissions Accountability Act* in Parliament. If passed, this Act will bind the Government of Canada to a process intended to help Canada achieve net-zero emissions by 2050. It will also establish rolling five-year emissions-reduction targets and require the government to develop plans to reach each target and support these efforts by creating a Net-Zero Advisory Body and require 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.

### *Alberta*

In November 2015, the Government of Alberta introduced a Climate Leadership Plan (the "**CLP**"). 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.

In June 2019, the federal fuel charge took effect in Alberta. In accordance with the GGPPA, the fuel charge payable in Alberta is currently \$30/tonne of CO<sub>2</sub>e and will increase to \$40/tonne on April 1, 2021. 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 and replaces the previous *Carbon Competitiveness Incentives Regulation*.

The TIER regulation applies to emitters that emit more than 100,000 tonnes of CO<sub>2</sub>e 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 1% 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 and facilities that are unable to achieve their targets may either purchase credits from other facilities, purchase carbon offsets, or pay a levy to the Government of Alberta.

The Government of Alberta aims to lower annual methane emissions by 45% by 2025. The Government of Alberta enacted the *Methane Emission Reduction Regulation* (the "**Alberta Methane Regulations**") on January 1, 2020, and the AER simultaneously released an updated edition of *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*. The release of the updated Directive 060 complements a previously released update to *Directive 017: Measurement Requirements for Oil and Gas Operations* that took effect in December 2018. Together, these Directives will support Alberta in achieving its 2025 goal. 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 \$40/tonne of CO<sub>2</sub>e. In response to COVID-19, the Government of British Columbia has delayed the scheduled increase to \$45/tonne of CO<sub>2</sub>e until April 1, 2021.

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 crude 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.

In January 2019, the BC Commission announced 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. These new rules came into effect on January 1, 2020. 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 50,000 tonnes are regulated to meet the province's reduction targets. The following regulations were enacted throughout 2018: *The Management and Reduction of Greenhouse Gases (General and Electricity Producer) Regulations*, the *Management and Reduction of Greenhouse Gases (Reporting and General) Regulations*, and *The Management and Reduction of Greenhouse Gases (Standards and Compliance) Regulations*. These Regulations establish reporting requirements and impose various emissions limits for those emitters that fall within the program. On January 1, 2019, *The Oil and Gas Emissions Management Regulations* (the "**Saskatchewan O&G Emissions Regulations**") came into effect. The Saskatchewan O&G Emissions Regulations apply to licensees of oil facilities that may generate more than 50,000 tonnes of CO<sub>2</sub>e per year, obliging each licensee to propose an emissions reduction plan in accordance with an annual emissions limit with the goal of achieving annual emissions reductions of 40 to 45% by 2025. The Saskatchewan O&G Emissions Regulations aim to achieve 4.5 million tonnes CO<sub>2</sub>e reduction in emissions by 2025, with a total reduction of 38.2 million tonnes of CO<sub>2</sub>e by 2030.

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

To facilitate its emissions reduction efforts, the Government of Saskatchewan has implemented *Directive PNG017: Measurement Requirements for Oil and Gas Operations*, which came into force in December 2019 and was amended in April 2020, and *Directive PNG036: Venting and Flaring Requirements*, which came into force in April 2020. Together with the Saskatchewan O&G Emissions Regulations, these directives enable the Government of Saskatchewan to regulate emissions reductions within the province. In November 2020, the Government of Canada and the Government of Saskatchewan announced that they had finalized an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in Saskatchewan.

## **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.**

### **The Impact of COVID-19 and Pandemics**

*Global or national health concerns, including the outbreak of pandemic or contagious diseases, such as the recent COVID-19 (coronavirus), may adversely affect the Corporation*

The Corporation's business, operations and financial condition could be materially adversely affected by the outbreak of epidemics or pandemics or other health crises. In December 2019, COVID-19 was reported to have surfaced in Wuhan, China. On January 30, 2020, the World Health Organization declared the outbreak a global health emergency and on March 11, 2020, the World Health Organization declared the outbreak a pandemic. The continued spread of COVID-19 throughout 2020 led to, among other things, significant restrictions on travel, quarantines, school closures, restrictions on public gatherings, business closures, travel restrictions and a general reduction in consumer activity.

The COVID-19 pandemic has negatively impacted the Canadian, U.S., and global economies; disrupted Canadian, U.S., and global supply chains; disrupted financial markets; contributed to a decrease in interest rates; resulted in ratings downgrades, credit deterioration and defaults in many industries; forced the closure of many businesses, led to loss of revenues, increased unemployment and bankruptcies; and necessitated the imposition of quarantines, physical distancing, business closures, travel restrictions, and sheltering-in-place requirements in Canada, the U.S., and other countries. If the pandemic is prolonged, including through subsequent waves, or if additional variants of COVID-19 emerge which are more transmissible or cause more severe disease, or if other diseases emerge with similar effects, the adverse impact on the economy could worsen. Moreover, it remains uncertain how the macroeconomic environment, and societal and business norms will be impacted following this COVID-19 pandemic. Unexpected developments in financial markets, regulatory environments, or consumer behaviour may also have adverse impacts on the Corporation's results, business, financial condition or liquidity, for a substantial period of time. At this point, the full extent to which COVID-19 has impacted the Corporation is uncertain; however, it is possible that COVID-19 may have a material adverse effect on the Corporation's business, results of operations and financial condition.

The outbreak of COVID-19 is one example of an illness capable of placing the Corporation at significant risk. There can be no assurance that COVID-19 or another infectious illness will not impact the Corporation's personnel and ultimately its operations. Pandemics, epidemics or outbreaks of an infectious disease in Canada or worldwide, including COVID-19, Middle East Respiratory Syndrome, Severe Acute Respiratory Syndrome, H1N1 influenza virus, avian flu or any other similar illnesses could have an adverse impact on the Corporation's results, business, financial condition or liquidity.

The Corporation's business, financial condition, results of operations, cash flows, reputation, access to capital, cost of borrowing, access to liquidity, and/or business plans may, in particular, and without limitation, be adversely impacted as a result of the pandemic and/or decline in commodity prices as a result of:

- the shut-down of facilities or the delay or suspension of work on major capital projects due to workforce disruption or labour shortages caused by workers becoming infected with COVID-19, or government or health authority mandated restrictions on travel by workers or closure of facilities or worksites;
- suppliers and third-party vendors experiencing similar workforce disruption or being ordered to cease operations;
- reduced cash flows resulting in less funds from operations being available to fund capital expenditure budgets;
- reduced commodity prices resulting in a reduction in the volumes and value of reserves;
- crude oil storage constraints resulting in the curtailment or shutting in of production;
- counterparties being unable to fulfill their contractual obligations on a timely basis or at all;
- the inability to deliver products to customers or otherwise get products to market caused by border restrictions, road or port closures or pipeline shut-ins, including as a result of pipeline companies suffering workforce disruptions or otherwise being unable to continue to operate; and
- the ability to obtain additional capital including, but not limited to, debt and equity financing being adversely impacted as a result of unpredictable financial markets, commodity prices and/or a change in market fundamentals.

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

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

### **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.

### **Weakness and Volatility in the Crude Oil and Natural Gas Industry**

***Weakness and volatility in the market conditions for the crude oil and natural gas industry may affect the value of the Corporation's reserves and restrict its cash flow and ability to access capital to fund the development of its properties***

Market events and conditions, including global excess oil and natural gas supply, the ongoing COVID-19 pandemic, actions taken by OPEC, sanctions against Iran and Venezuela, slowing growth in China and emerging economies, weakening global relationships, conflict between the U.S. and Iran, isolationist and punitive trade policies, U.S. shale production, sovereign debt levels and political upheavals in various countries including growing anti-fossil fuel sentiment, have caused significant volatility in commodity prices. See "*Risk Factors – Political Uncertainty*" and "*Risk Factors - The Impact of COVID-19 and Pandemics*". These events and conditions have caused a significant reduction in the valuation of oil and natural gas companies and a decrease in confidence in the crude oil and natural gas industry. These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. See "*Risk Factors – Royalties and Incentives*", "*Industry Conditions – Regulatory Authorities and Environmental Regulation*" and "*Industry Conditions – Climate Change Regulation*". In addition, the difficulties encountered by midstream proponents to obtain the necessary approvals on a timely basis to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the crude oil and natural gas industry in Western Canada has led to additional downward price pressure on oil and natural gas produced in Western Canada. The resulting price differential between Western Canadian Select crude oil, and Brent and West Texas Intermediate crude oil has created uncertainty and reduced confidence in the crude oil and natural gas industry in Western Canada. See "*Industry Conditions – Transportation Constraints and Market Access*".

Lower commodity prices may also affect the volume and value of the Corporation's reserves, rendering certain reserves uneconomic. In addition, lower commodity prices restrict the Corporation's cash flow resulting in less funds from operations being available to fund the Corporation's capital expenditure budget. Consequently, the Corporation may not be able to replace its production with additional reserves and both the Corporation's production and reserves could be reduced on a year-over-year basis. See "*Risk Factors – Reserves Estimates*". Any decrease in value of the Corporation's reserves may reduce the borrowing base under the Credit facilities, which, depending on the level of the Corporation's indebtedness, could result in the Corporation having to repay a portion of its indebtedness. See "*Risk Factors – Credit Facilities*". In addition to possibly resulting in a decrease in the value of the Corporation's economically recoverable reserves, lower commodity prices may also result in a decrease in the value of the Corporation's infrastructure and facilities, all of which could also have the effect of requiring a write down of the carrying value of the Corporation's oil and natural gas assets on its balance sheet and the recognition of an impairment charge in its income statement. Given the current market conditions and the lack of confidence in the Canadian oil and natural gas industry, the Corporation may have difficulty raising additional funds or if it is able to do so, it may be on unfavourable and highly dilutive terms. See "*Risk Factors – Additional Funding Requirements*".

## 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 the near future because of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, the ongoing COVID-19 pandemic, shale oil production in the United States, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries, conflicts in the Middle East and ongoing credit and liquidity concerns. 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*" and "*Risk Factors – Weakness and Volatility in the crude oil and natural gas Industry*".

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.

### **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.

### **Political Uncertainty**

#### ***The Corporation's business may be adversely affected by recent political and social events and decisions made in Canada, the United States, Europe and elsewhere***

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

In addition, the United States Mexico Canada Agreement (the "**USMCA**"), which replaced the former North American Free Trade Agreement ("**NAFTA**") was ratified on July 1, 2020 and may impact the Corporation's business. See "*Industry Conditions – The North American Trade Agreement and Other Trade Agreements*".

The newly-inaugurated Biden administration in the U.S. has indicated that it will roll-back certain policies of the former administration, and has taken action to cancel TC Energy Corporation's Keystone X.L. pipeline permit. While it is unclear which other legislation or policies of the former Trump administration will be rolled-back and if such roll-backs will be a priority of the new administration in light of the ongoing COVID-19 pandemic, any future actions taken by the new U.S. administration could have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and natural gas companies, including the Corporation.

In addition to the changing political landscape in the United States, the impact of the United Kingdom's exit from the European Union are slowly emerging and some impacts may not become apparent for some time. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. Conflict and political uncertainty also continues to progress in the Middle East. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement, it could have an adverse effect on the Corporation's ability to market its products internationally, increase costs for goods and services required for the Corporation's operations, reduce access to skilled labour and negatively impact the Corporation's business, operations, financial conditions and the market value of the Common Shares.

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 crude oil and natural gas industry including the balance between economic development and environmental policy.

The United Conservative Party government in Alberta is supportive of the Trans Mountain Pipeline expansion project and, although there has been notable opposition from the government of British Columbia, the federal Government remains in support of the project. Continued uncertainty and delays have led to decreased investor confidence, increased capital costs and operational delays for producers and service providers operating in the jurisdiction where the Corporation is active.

The federal Government was re-elected in 2019, but in a minority position. The ability of the minority federal government to pass legislation will be subject to whether it is able to come to agreement with, and garner the support of, the other elected parties, most of whom are opposed to the development of the crude oil and natural gas industry. The minority federal government will also be required to rely on the support of the other elected parties to remain in power, which provides less stability and may lead to an earlier subsequent federal election. Political instability, at both the federal and provincial level, continues to create regulatory uncertainty, the effects of which become apparent on an ongoing basis, particularly with respect to carbon pricing regimes, curtailment of crude oil production and transportation and export capacity, and may affect the business of participants

in the crude oil and natural gas industry. See "*Industry Conditions – Climate Change Regulation*", "*Industry Conditions – Transportation Constraints and Market Access*", "*Industry Conditions – Curtailment*" and "*Industry Conditions – The North American Free Trade Agreement and other Trade Agreements*".

## **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 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, pipeline systems and, in certain circumstances, by rail. 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, pipeline systems and railway lines. The lack of firm pipeline capacity, production limits and limits on availability of capacity in gathering and processing facilities continues to affect the crude oil and natural gas industry and limits the ability to transport produced oil and natural gas to market. See "*Industry Conditions – Transportation Constraints and Market Access*" and "*Industry Conditions – Curtailment*". In addition, the prorationing of capacity on inter-provincial pipeline systems continues to affect the ability of oil and natural gas companies to export oil and natural gas, and could result in the Corporation's inability to realize the full economic potential of its products or in a reduction of the price offered for the Corporation's production. 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. As a result, producers have considered rail lines as an alternative means of transportation. Announcements and actions taken by the federal government and the provincial governments of British Columbia, Alberta and Quebec relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. In August 2019, the CERA and the IAA came into force resulting in changes to the federal regulation and associated environmental assessments of major projects. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*". The impact of the new federal regulatory scheme on proponents, and the timing for receipt of approvals, of major projects is unclear.

In January 2021, U.S President Biden took steps to cancel the presidential permit that had allowed the Keystone XL Pipeline to operate across Canadian and American borders. It is unclear if challenges to the revocation of the permit will be successful and what the direct impact of the loss of permit will be on the Corporation.

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 – Liability Management Rating Program*" and "*Risk Factors – Third Party Credit Risk*".

### **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***

The implementation of new regulations or the modification of existing regulations affecting the crude oil and natural gas industry could reduce demand for crude 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. Further, the ongoing third party challenges to regulatory decisions or orders has reduced the efficiency of the regulatory regime, as the implementation of the decisions and orders has been delayed resulting in uncertainty and interruption to business of the crude oil and natural gas industry. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulations*". Also, in response to widening pricing differentials, the Government of Alberta implemented production curtailment. See "*Industry Conditions – Curtailment*" and "*Risk Factors – Liability Management*".

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 Rating Programs*".

## **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 – Exports from Canada*", "*Industry Conditions – Regulatory Authorities and Environmental Regulation*" and "*Industry Conditions – Climate Change 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 may pose varied and far ranging risks to the business and operations of the Corporation, both known and unknown, that may adversely affect the Corporation's business, financial condition, results of operations, prospects, reputation and share price***

### ***Chronic Climate Change Risks***

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

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

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

Given the evolving nature of climate change policy and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing the Corporation's operating expenses, and, in the long-term, potentially reducing the demand for oil and natural gas production, resulting in a decrease in the Corporation's profitability and a reduction in the value of its assets or requiring asset impairments for financial statement purposes. As at the date hereof, Gear's current emission levels are not subject to any climate change regulations. See "*Description of the Business – Environmental Considerations and Protection*", "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*", "*Risk Factors – Non-Governmental Organizations*", "*Risk Factors – Reputational Risk Associated with the Corporation's Operations*" and "*Risk Factors – Changing Investor Sentiment*".

### ***Acute Climate Change Risk***

Climate change has been linked to extreme weather conditions. Extreme hot and cold weather, heavy snowfall, heavy rainfall and wildfires may restrict the Corporation's ability to access its properties, cause operational difficulties including damage to machinery and facilities. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions. None of the Corporation's assets are located in locations that are proximate to forests / rivers and a wildfire / flood will not lead to significant downtime and/or damage to such assets. Moreover, extreme weather conditions may lead to disruptions in the Corporation's ability to transport produced oil and natural gas as well as goods and services in its supply chain.

## 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.

An increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt, resulting in a reduced amount available to fund its exploration and development activities, and if applicable, the cash available for dividends. Such an increase could also negatively impact the market price of the Common Shares.

## 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.

See "*Industry Conditions – Royalties and Incentives*".

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 or terminate 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.

## **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 currently has the Credit Facilities and the amount authorized thereunder is dependent on the borrowing base determined by its lenders. The Corporation is required to comply with covenants under the Credit Facilities which may, in certain cases, 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 failure of the Corporation to comply with such covenants. A failure to comply with covenants could result in default under the 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 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, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

The Corporation's lenders use the Corporation's reserves, commodity prices, applicable discount rate and other factors, to periodically determine the Corporation's borrowing base. As a result of the depressed commodity prices experienced in the last two (2) years, the Corporation's borrowing base was reduced in May 2019. There remains a substantial amount of uncertainty as to when and if commodity prices will recover. Continued depressed commodity prices or further reductions in commodity prices could result in a further reduction to the Corporation's borrowing base, reducing the funds available to the Corporation under the credit facility. This could result in the requirement to repay a portion, or all, of the Corporation's indebtedness.

The Supreme Court of Canada's decision in Redwater has given rise to new covenants and restrictions under the Corporation's credit facilities, should LMR levels fall below existing agreed-upon thresholds, including further limitations on asset dispositions and acquisitions. The Corporation may also be required to provide additional reporting to its lenders regarding its existing and/or budgeted abandonment and reclamation obligations, its decommissioning expenses, its LMR and/or any notices or orders



received from an energy regulator in any applicable province. The Corporation's lenders may also be permitted to re-determine the Corporation's borrowing base (at the sole cost of the Corporation) following a decline in its LMR below a certain threshold or if the Corporation becomes subject to an abandonment and reclamation order and its estimated cost of compliance with such order exceeds a certain threshold. See also "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs*".

If the Corporation's lenders require repayment of all or a portion of the amounts outstanding under its credit facilities for any reason, including for a default of a covenant, or the reduction of a borrowing base, 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 its 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 credit facilities, the lenders under its 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.

### **Availability and Cost of Material and Equipment**

***Restrictions on the availability and cost of materials and equipment may impede the Corporation's exploration, development and operating activities***

Oil and natural gas exploration, development and operating activities are dependent on the availability and cost of specialized materials and equipment (typically leased from third parties) in the areas where such activities are conducted. The availability

of such material and equipment is limited. An increase in demand or cost, or a decrease in the availability of such materials and equipment may impede the Corporation's exploration, development and operating activities.

### **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.

## **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. See "*Industry Conditions – Transportation Constraints and Market Access*". 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.

## **Dividends**

***The Corporation does not pay dividends and there is no assurance that it will do so in the future***

The Corporation has not paid any dividends on its outstanding shares. Payment of dividends in the future will be dependent on, among other things, cash flow, results of operations, financial condition of the Corporation, the need for funds to finance ongoing operations and other considerations, as the Board considers relevant.

## **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 Claims**

***Indigenous claims may affect the Corporation***

Indigenous peoples have claimed Indigenous rights and title in portions of Western Canada. The Corporation is not aware that any claims have been made in respect of its properties and assets. However, if a claim arose and was successful, such claim may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, the process of addressing such claims, regardless of the outcome, is expensive and time consuming and could result in delays in the construction of infrastructure systems and facilities which could have a material adverse effect on the Corporation's business and financial results.

## **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. 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. The ongoing COVID-19 pandemic has increased the Corporation's cyber-attacks, as increased malicious activities are creating more threats for cyberattacks including COVID-19 phishing emails, malware-embedded mobile apps that purport to track infection rates, and targeting of vulnerabilities in remote access platforms as many companies continue to operate with work from home arrangements.

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.

## **Social Media**

*The Corporation faces compliance and supervisory challenges in respect of the use of social media as a means of communicating with clients and the general public*

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.

## **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. Additionally, these factors, as well as other related factors, may cause a decrease in the value of the Corporation's asset which may result in an impairment change.

### **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.

### **Carbon Pricing Risk**

*Taxes on carbon emissions affect the demand for oil and natural gas, the Corporation's operating expenses and may impair the Corporation's ability to compete*

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In Canada, the federal government implemented legislation aimed at incentivizing the use of alternative fuels and in turn reducing carbon emissions. The federal system applies in provinces and territories that request it to be implemented or are without their own system that meets federal standards. The federal regime is subject to a number of court challenges by Alberta, Saskatchewan and Ontario. The final decision from the Supreme Court of Canada is expected to be delivered sometime in 2021. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*". Any taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products and at the same time, increasing the Corporation's operating expenses, each of which may have a material adverse effect on the Corporation's profitability and financial condition. Further, the imposition of carbon taxes puts the Corporation at a disadvantage with its counterparts who operate in jurisdictions where there are less costly carbon regulations.

### **Disposal of Fluids Used in Operations**

***Regulations regarding the disposal of fluids used in the Corporation's operations may increase its costs of compliance or subject it to regulatory penalties or litigation***

The safe disposal of the hydraulic fracturing fluids (including the additives) and water recovered from oil and natural gas wells is subject to ongoing regulatory review by the federal and provincial governments, including its effect on fresh water supplies and the ability of such water to be recycled, amongst other things. While it is difficult to predict the impact of any regulations that may be enacted in response to such review, the implementation of stricter regulations may increase the Corporation's costs of compliance.

### **Intellectual Property Litigation**

***Unauthorized use of intellectual property may cause the Corporation to engage in, or be the subject of, litigation***

Due to the rapid development of oil and natural gas technology, in the normal course of the Corporation's operations, the Corporation may become involved in, named as a party to, or be the subject of, various legal proceedings in which it is alleged that the Corporation has infringed the intellectual property rights of others or which the Corporation initiates against others it believes are infringing upon its intellectual property rights. The Corporation's involvement in intellectual property litigation could result in significant expense, adversely affecting the development of its assets or intellectual property or diverting the efforts of its technical and management personnel, whether or not such litigation is resolved in the Corporation's favour. In the event of an adverse outcome as a defendant in any such litigation, the Corporation may, among other things, be required to:

- (a) pay substantial damages and/or cease the development, use, sale or importation of processes that infringe upon other patented intellectual property;
- (b) expend significant resources to develop or acquire non-infringing intellectual property;
- (c) discontinue processes incorporating infringing technology; or
- (d) obtain licences to the infringing intellectual property.

However, the Corporation may not be successful in such development or acquisition, or such licences may not be available on reasonable terms. Any such development, acquisition or licence could require the expenditure of substantial time and other resources and could have a material adverse effect on the Corporation's business and financial results.

**ADDITIONAL INFORMATION**

Additional information relating to Gear may be found on SEDAR at [www.sedar.com](http://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, 2020, which documents may be found on SEDAR at [www.sedar.com](http://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, 2020. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2020, 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, 2020, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – M\$)			
			Audited	Evaluated	Reviewed	Total
Sproule Associates Limited	December 31, 2020	Canada	Nil	220,265	Nil	220,265

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 3, 2021.

(Signed) "Stephanie D. Brunt"  
**Stephanie D. Brunt, P.Eng.**  
**Project Leader; Petroleum 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) "Bindu Wyma"  
Bindu Wyma  
Director

March 22, 2021

## 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:

5. To assist directors of Gear ("**Directors**") in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of the Corporation and related matters;
6. To provide better communication between Directors and external auditors;
7. To enhance the external auditor's independence;
8. To increase the credibility and objectivity of financial reports; and
9. 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:
  - 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;
  - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
  - reviewing accounting treatment of unusual or non-recurring transactions;
  - ascertaining compliance with covenants under loan agreements;
  - reviewing disclosure requirements for commitments and contingencies;
  - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
  - reviewing unresolved differences between Management and the external auditors; and
  - 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 accuracy of those procedures.
5. With respect to the appointment of external auditors by the Board:
  - recommend to the Board the external auditors to be nominated;
  - 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;
  - 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;
  - 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; and

- 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. Establish a procedure for:
    - the receipt, retention and treatment of complaints received by Gear regarding accounting, internal accounting controls or auditing matters; and
    - the confidential, anonymous submission by employees of Gear of concerns regarding questionable accounting or auditing matters.
  10. 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.

The Committee may also retain persons having special expertise and/or obtain independent professional advice to assist in filling their responsibilities at such compensation as established by the Committee and at the expense of Gear without any further approval of the Board.

### **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 Chairman of the meeting shall 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. 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 Chairman.
5. The Committee will meet with the external auditor 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.



6. Agendas, approved by the Chair, will be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.
7. 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.
8. 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.
9. The Committee may retain persons having special expertise and may obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Corporation as determined by the Committee.
10. 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.
11. Any issues arising from these meetings that bear on the relationship between the Board and Management should be communicated to the Chairman of the Board by the Committee Chair.
12. 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.

March 26, 2018