



---

**Annual Information Form**

For the Year Ended December 31, 2023  
Dated March 6, 2024

## Table of Contents

Select Definitions .....	3
Abbreviations and Conversion .....	4
Non-IFRS Measures .....	5
Notes on Reserves Data and Other Oil and Natural Gas Information .....	5
Special Note Regarding Forward Looking Statements .....	8
Surge Energy Inc. ....	10
Development of the Business .....	11
Description of the Business.....	12
Principal Producing Properties.....	14
Statement of Reserves Data.....	17
Description of Capital Structure .....	27
Dividend Policy.....	28
Market for Securities .....	29
Directors and Officers .....	30
Audit Committee.....	34
Industry Conditions .....	36
Risk Factors .....	64
Material Contracts .....	92
Legal Proceedings And Regulatory Actions.....	92
Interest of Management and Others in Material Transactions.....	92
Auditor, Transfer Agent and Registrar .....	92
Interest of Experts .....	93
Additional Information .....	93
Schedule "A" – Form 51-101F2	
Schedule "B" – Form 51-101F3	
Schedule "C" – Audit Committee Charter	

## SELECT DEFINITIONS

Unless the context indicates otherwise, the following terms shall have the meanings set out below when used in this Annual Information Form. Certain other terms and abbreviations used herein, but not defined herein, are defined in NI 51-101 or the COGE Handbook and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 or the COGE Handbook.

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

"**AIF**" or "**Annual Information Form**" means this annual information form;

"**Audit Committee**" means the audit committee of the Board;

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

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

"**Common Shares**" means the common shares of the Corporation;

"**Corporation**" or "**Surge**" means Surge Energy Inc., a corporation amalgamated under the ABCA;

"**Credit Facilities**" means, collectively, the First Lien Credit Facilities and the Second Lien Term Debt Facility;

"**Current Market Price**" means, generally, the volume weighted average trading price of the Common Shares for the applicable period, on the TSX (or if the Common Shares are no longer traded on the TSX, on such other exchange as the Common Shares are then traded) for the 20 consecutive trading days ending on the fifth trading day preceding the applicable date. If the Common Shares are not listed or quoted on the TSX or another securities exchange or market, "**Current Market Price**" shall be the fair value of a Common Share as reasonably determined by the Board of Directors;

"**Debentures**" means the 8.50% convertible unsecured subordinated debentures due on December 31, 2028, as more particularly described under the heading "*Description of Capital Structure - Debentures*";

"**First Lien Credit Facilities**" means the aggregate \$150 million first lien secured credit facilities of the Corporation with a syndicate of lenders, comprised of a \$120 million revolving credit facility and a \$30 million operating credit facility;

"**IFRS**" means International Financial Reporting Standards, as issued by the International Accounting Standards Board, as amended from time to time;

"**Indenture**" means the debenture indenture dated May 8, 2019 between Surge and Computershare Trust Company of Canada, as amended on November 15, 2017 and as supplemented by a first supplemental debenture indenture dated May 8, 2019 and a second supplemental indenture dated October 19, 2023, under which the Debentures were issued;

"**NGL**" means natural gas liquids;

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

"**NI 51-102**" means National Instrument 51-102 – *Continuous Disclosure Requirements*;

**"Reserves Report"** means the independent engineering report with a preparation date of February 9, 2024 and effective December 31, 2023 prepared by and containing the evaluation of Sproule of the oil, NGL and natural gas reserves attributable to the properties of the Corporation, dated as of February 16, 2024;

**"Second Lien Term Debt Facilities"** means the non-revolving second lien secured credit facilities of the Corporation, comprised, as of the date hereof, of an approximate \$160 million Term A credit facility and an approximate \$40 million Term B credit facility;

**"Sproule"** means Sproule Associates Limited, independent oil and gas reservoir engineers;

**"TSX"** means the Toronto Stock Exchange; and

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

Words importing the singular number only include the plural, and vice versa, and words importing any gender include all genders. All dollar amounts set forth in this Annual Information Form, including "dollar", "\$" and "CAD\$" are in Canadian dollars, except where otherwise indicated. "US\$" means United States dollars.

### ABBREVIATIONS AND CONVERSION

In this Annual Information Form, the abbreviations set forth below have the following meanings:

<b>Oil and Natural Gas Liquids</b>		<b>Natural Gas</b>	
bbl	Barrel	Mcf	thousand cubic feet
bbls	Barrels	MMcf	million cubic feet
Mbbls	thousand barrels	Mcf/d	thousand cubic feet per day
MMbbls	million barrels	MMcf/d	million cubic feet per day
Mstb	1,000 stock tank barrels	MMbtu	million British Thermal Units
bbl/d	barrels per day	Bcf	billion cubic feet
NGLs	natural gas liquids	GJ	gigajoule
stb	stock tank barrel		

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

<b>To Convert From</b>	<b>To</b>	<b>Multiply By</b>
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls	6.293
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.50
Gigajoules	MMbtu	0.950
MMbtu	Gigajoules	1.0526

## Other

AECO	a 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. Liquid petroleum with a specified gravity of 35.1° API or greater is generally referred to as light crude oil. Liquid petroleum with a specified gravity of 25.8° to 35° API or greater is generally referred to as medium crude oil. Liquid petroleum with a specified gravity of 25.7° API or lower is generally referred to as heavy crude oil.
boe	barrel of oil equivalent on the basis of 1 boe to 6 Mcf of natural gas. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 1 boe for 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead
boe/d	barrel of oil equivalent per day
m <sup>3</sup>	cubic metres
Mboe	1,000 barrels of oil equivalent
MMboe	1,000,000 barrels of oil equivalent
\$000s	thousands of dollars
M\$ or \$M	thousands of dollars
MM\$	millions of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

## NON-IFRS MEASURES

This AIF contains the term "operating netback" which is not defined by IFRS and therefore may not be comparable to performance measures presented by others. In this AIF, "operating netback" is calculated by deducting royalties paid and production costs, including transportation costs, from prices received, excluding the effects of hedging. Management believes that in addition to net income, operating netbacks are a useful supplemental measure as it assists in the determination of the Corporation's operating performance. Readers should be cautioned, however, that this measure should not be construed as an alternative to both net income and net cash from (used in) operating activities, which are determined in accordance with IFRS, as indicators of the Corporation's performance.

## NOTES ON RESERVES DATA AND OTHER OIL AND NATURAL GAS INFORMATION

### Caution Respecting Reserves Information

The determination of oil and natural gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved and probable reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery. The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

**The recovery and reserve estimates of oil, NGL and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein. The**

**estimated future net revenue from the production of the Corporation's natural gas and petroleum reserves does not represent the fair market value of the Corporation's reserves.**

### **Caution Respecting Boe**

In this AIF, the abbreviation boe means barrel of oil equivalent on the basis of 1 boe to 6 Mcf of natural gas when converting natural gas to boes. **Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 1 boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.**

### **Definitions**

Certain terms used in this AIF in describing reserves and other oil and natural gas information are defined below. Certain other terms and abbreviations used in this AIF, but not defined or described, are defined in NI 51-101 or the COGE Handbook and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 or the COGE Handbook.

#### *Reserves*

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: (i) analysis of drilling, geological, geophysical and engineering data; (ii) the use of established technology; and (iii) specified economic conditions, which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates as follows:

**"proved reserves"** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

**"probable reserves"** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

The qualitative certainty levels referred to in the definitions above are applicable to "individual reserves 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 reserves estimates are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

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

Each of the reserves categories (proved and probable) may be divided into developed and undeveloped categories as follows:

**"developed reserves"** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing as follows:

**"developed producing reserves"** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

**"developed non-producing reserves"** are those reserves that either have not been on production, or have previously been on production but are shut-in and the date of resumption of production is unknown.

**"undeveloped reserves"** are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves' classification (proved, probable, possible) to which they are assigned.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to sub-divide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

#### *Interests in Reserves, Production, Wells and Properties*

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

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

**"working interest"** means the percentage of undivided interest held by an issuer in the oil and/or natural gas or mineral lease granted by the mineral owner, Crown or freehold, which interest gives the issuer the right to "work" the property (lease) to explore for, develop, produce and market the leased substances.

#### *Description of Exploration and Development Wells and Costs*

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

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

**"exploration costs"** means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and natural gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "prospecting costs") and after acquiring the property.

Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are: (i) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as "geological and geophysical costs"); (ii) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records; (iii) dry hole contributions and bottom hole contributions; (iv) costs of drilling, completing and equipping exploratory wells; and (v) costs of drilling exploratory type stratigraphic test wells.

**"exploration well"** means a well that is not a development well, a service well or a stratigraphic test well.

**"service well"** means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

#### **SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS**

Certain statements or disclosures contained in this Annual Information Form constitute forward-looking statements. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe" and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Corporation believes the expectations reflected in those forward-looking statements are reasonable, but no assurance can be given that these expectations will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Such forward-looking statements included in this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form.

In particular, this Annual Information Form may contain forward-looking statements and information pertaining to the following:

- the performance characteristics of the Corporation's oil and natural gas properties;
- oil and natural gas production levels, and expectations of future production rates, volumes and product mixes;
- the size of the oil and natural gas reserves of the Corporation and anticipated future cash flows from such reserves;
- projections of market prices and costs, and exchange and inflation rates;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- the Corporation's dividend policy;



- treatment under governmental regulatory regimes and tax and royalty laws;
- criteria and considerations in participations and acquisitions;
- the Corporation's tax horizon;
- timing of development of undeveloped reserves;
- estimated abandonment and reclamation costs and the timing thereof;
- expected land expiries and plans with respect thereto;
- plans to implement enhanced recovery; and
- capital expenditure programs, the allocation of such capital and the timing thereof.

With respect to forward looking statements contained in this Annual Information Form, the Corporation has made assumptions regarding:

- oil and natural gas production levels and the timing of new wells coming on-stream;
- the success of the Corporation's operations and exploration and development activities;
- the size of Surge's oil, natural gas and NGL reserves and the recoverability of its reserves;
- prevailing weather conditions, commodity prices and exchange rates;
- the availability of labour, services and drilling equipment;
- the availability of capital to fund planned expenditures;
- timing and amount of capital expenditures;
- timing of production curtailments;
- future operating costs and future cash flow;
- the Corporation's future debt levels;
- general economic and financial market conditions;
- the Corporation's ability to market production of oil and natural gas successfully to customers;
- the applicability of technologies for recovery and production of the Corporation's reserves;
- the success, nature and timing of water flood activities;
- the ability of the Corporation to secure necessary capital, personnel, equipment and services; and
- government regulation in the areas of taxation, royalty rates and environmental protection.

The actual results, performance or achievements of the Corporation may differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Annual Information Form:

- volatility in market prices for oil and natural gas;
- volatility in exchange rates;
- liabilities inherent in oil and natural gas operations;
- the impact of pandemics and public health emergencies and the impacts on field activity levels, health and safety considerations and restrictions which may impact the ability of the Corporation to carry on business as planned;
- the impact of geopolitical actions, including war (including the Russia-Ukraine conflict and conflict in the Middle East) and terrorism;
- uncertainties associated with estimating oil and natural gas reserves and production levels;
- uncertainty surrounding the amount that will be available under the Credit Facilities in the future;
- inability to secure labour, services or equipment on a timely basis or on favourable terms;
- failure to obtain industry partner, regulatory or other third-party consents and approvals, when required;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- fluctuations in the cost of borrowing;
- the marketability of production and demand of Surge's products;

- the inability to access sufficient capital from internal and external sources;
- changes in general economic, market and business conditions;
- a decrease or elimination of the payment of dividends by the Corporation as a result of the Board of Directors determination or restrictions under applicable agreements or corporate laws;
- unanticipated operating events which can reduce production or cause production to be shut in or delayed;
- unfavourable weather conditions;
- a failure of the Corporation to hire or retain key personnel;
- incorrect assessments of the value of acquisitions, dispositions and exploration and development programs;
- geological, technical, drilling, completion and processing problems;
- results of water flood responses;
- the outcome of litigation or regulatory proceedings brought against the Corporation or other disputes involving the Corporation;
- changes in legislation, including changes in tax laws and incentive programs relating to the oil and gas industry;
- the impact of or natural disasters including earthquakes, typhoons, floods and fires;
- cyber-security issues;
- failure to realize the anticipated benefits of acquisitions and dispositions; and
- the other factors discussed under "*Risk Factors*".

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

**Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this Annual Information Form are expressly qualified by this cautionary statement. The Corporation does not undertake any obligation to publicly update or revise any forward-looking statements other than as required under applicable securities laws.**

## **SURGE ENERGY INC.**

### **Corporate Structure**

Surge was incorporated on January 26, 1998 under the ABCA as "Zapata Capital Inc." On June 18, 1999, the Corporation acquired all of the issued and outstanding shares of 744997 Alberta Ltd. and amalgamated with 744997 Alberta Ltd. under the name "Zapata Energy Corporation". On June 25, 2010, the Corporation changed its name to "Surge Energy Inc." On December 31, 2010, the Corporation amalgamated with its wholly-owned subsidiary, Breaker Resources Ltd. On December 31, 2012, the Corporation amalgamated with its wholly-owned subsidiary, Surge Oil Inc. On December 31, 2013, the Corporation amalgamated with its wholly-owned subsidiaries, Flagstone Energy Inc. and 1779275 Alberta Ltd. On December 31, 2014, the Corporation amalgamated with its wholly-owned subsidiary, Longview Oil Corp. On December 31, 2018, the Corporation amalgamated with its wholly-owned subsidiary, Mount Bastion Oil & Gas Corp. On August 18, 2021, the Corporation amalgamated with its wholly-owned subsidiary, Surge Acquisition Co Ltd. On August 20, 2021 the Corporation amended its articles to effect a consolidation of the Common Shares. On November 1, 2021, the Corporation amalgamated with its wholly-owned subsidiary, 2385316 Alberta Ltd. On December 31, 2021, the Corporation amalgamated with its wholly-owned subsidiary, 1413942 Alberta Ltd.

The head office of the Corporation is located at Suite 1200, 520 – 3<sup>rd</sup> Avenue S.W., Calgary, Alberta T2P 0R3. The registered office of the Corporation is located at Suite 4000, 421 – 7<sup>th</sup> Avenue S.W., Calgary, Alberta, T2P 4K9.

## DEVELOPMENT OF THE BUSINESS

### General

The Corporation is an independent oil and gas company based in Calgary, Alberta and operating in Alberta, Saskatchewan and Manitoba. The Common Shares are listed on the TSX under the symbol "SGY". The Debentures are listed on the TSX under the symbol "SGY.DB.B".

### Three Year History

Significant developments of the Corporation over the last three completed financial years are as set forth below:

#### *Year Ended December 31, 2021*

On March 25, 2021, Surge completed the sale of certain core assets in Northeast Alberta and Southeast Alberta for aggregate proceeds of \$106 million.

On August 18, 2021, Surge completed its acquisition of Astra Oil Corp. ("**Astra**") pursuant to a plan of arrangement under the provisions of the ABCA for a purchase price of approximately \$160 million. Concurrent with the acquisition of Astra, Surge's fully conforming first lien revolving credit facilities were set at \$215 million.

On November 1, 2021, Surge completed its acquisition of Fire Sky Energy Inc. ("**Fire Sky**") following the amalgamation of Fire Sky and a wholly-owned subsidiary of Surge under the provisions of *The Business Corporations Act* (Saskatchewan) for a purchase price of approximately \$58 million.

#### *Year Ended December 31, 2022*

On October 28, 2022 (the "**Original Redemption Date**"), Surge redeemed all of its then outstanding 5.75% convertible unsecured subordinated debentures originally due on December 31, 2022, paying the aggregate principal amount of the such debentures (being \$1,000 per debenture) plus all unpaid interest thereon to, but excluding the Original Redemption Date. These debentures, which had traded on the TSX under the symbol "SGY.DB", were delisted from the TSX on the Original Redemption Date.

On December 19, 2022, Surge completed an acquisition of crude oil assets in Surge's Sparky and Southeast Saskatchewan core areas from Enerplus Corporation for net proceeds of \$198 million (the "**Enerplus Acquisition**").

#### *Year Ended December 31, 2023*

On October 19, 2023, Surge issued \$48.3 million principal amount of Debentures. The Debentures will mature and be repayable on December 31, 2028 and accrue interest at a rate of 8.50 percent per annum. The Debentures are listed on the TSX under the symbol "SGY.DB.B". See "*Description of Capital Structure - Debentures*".

On November 18, 2023 (the "**Series 2 Redemption Date**"), Surge redeemed all of the outstanding 6.75% convertible unsecured subordinated debentures originally due on June 30, 2024, paying the aggregate

principal amount of the such debentures (being \$1,000 per debenture) plus all unpaid interest thereon to, but excluding the Series 2 Redemption Date. These debentures, which had traded on the TSX under the symbol "SGY.DB.A", were delisted from the TSX immediately following the Series 2 Redemption Date.

### **Significant Acquisitions**

Surge did not complete any "significant acquisitions" (as such term is defined in NI 51-102) during the financial year ended December 31, 2023.

## **DESCRIPTION OF THE BUSINESS**

### **Overview**

The Corporation is an oil and gas exploration, development and production company. Surge holds focused and operated light and medium gravity crude oil properties in Alberta, Saskatchewan and Manitoba, characterized by large oil in place crude oil reservoirs with low recovery factors. The Corporation has a significant inventory of low risk development drilling locations, including several successful water flood projects.

### **Corporate Strategy**

The Corporation focuses on assets with the following criteria: large oil in place with low recovery factors; available infrastructure; high working interest; operatorship; all-season access and drilling inventory; water flood opportunities; and other upside that provides a definable high rate of return.

Management believes in controlling the timing and costs of the Corporation's projects wherever possible. Accordingly, the Corporation seeks to become the operator of its properties. Further, to minimize competition within its geographic areas of interest, the Corporation strives to maximize its working interest ownership in its properties where reasonably possible.

In reviewing potential drilling or acquisition opportunities, the Corporation gives consideration to the following criteria: risk capital to secure or evaluate the opportunity; the potential return on the project, if successful; the likelihood of success; and risked return versus cost of capital.

In general, the Corporation pursues a portfolio approach in developing a large number of opportunities with a balance of risk profiles in an attempt to generate sustainable levels of growth. The Board of Directors may, in its discretion, approve asset or corporate acquisitions or investments that do not conform to the guidelines discussed above based upon the Board's consideration of the qualitative aspects of the subject properties, including risk profile, technical upside, reserve life and asset quality.

In addition, the management team of the Corporation, as described below under "*Directors and Officers*", is continually assessing the assets and operations of the Corporation, including its existing land base, facilities, reserves, prospects and personnel.

### **Competition**

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

believes that its competitive position is equivalent to that of other oil and gas issuers of similar size and at a similar stage of development.

### **Cyclical and Seasonal Nature of Industry**

Surge's operational results and financial condition are dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated dramatically during recent years and are determined by a number of factors, including global and local supply and demand factors, and including weather and general economic conditions, as well as conditions in other oil and natural gas producing and consuming regions. Surge attempts to mitigate such price risk through closely monitoring commodity markets and establishing disciplined hedging programs.

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.

Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Corporation. Demand for natural gas typically rises during cold winter months and hot summer months.

### **Environmental Regulation**

The oil and natural gas industry is subject to environmental regulations pursuant to a variety of provincial and federal legislation. Compliance with such legislation can require significant expenditures or result in operational restrictions. Breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties, all of which might have a significant negative impact on earnings and overall competitiveness. See below under the headings "*Industry Conditions – Regulatory Authorities and Environmental Regulation*" and "*Risk Factors – Environmental*".

The Corporation is obligated to abandon, retire and reclaim wells and well sites in compliance with applicable environmental laws and regulations. As of December 31, 2023, the Corporation has recorded an asset retirement obligation of \$263 million. The Corporation anticipates that the expenditures necessary to satisfy the asset retirement obligation will be incurred over a period of 20 years, with the majority of the expenditures being incurred from years 2024 to 2044. Other than asset retirement obligations and ordinary course operational expenditures necessary to ensure environmental compliance, the Corporation is not aware of any environmental protection requirement that will impact its capital expenditures, earnings or competitive position in a manner disproportionate to that of its peers in its area of operations.

### **Marketing**

Surge's crude oil and natural gas production are sold primarily through marketing companies at current market prices.

The Corporation uses a variety of derivative instruments to reduce its exposure to fluctuations in commodity prices and foreign exchange rates as described under "*Statement of Reserves Data – Other Oil and Gas Information – Forward Contracts*". For details of the Corporation's forward contracts in place as at December 31, 2023, see the Corporation's audited annual financial statements for the year ended

December 31, 2023, which have been filed on SEDAR+ and may be viewed under the Corporation's profile at [www.sedarplus.com](http://www.sedarplus.com). See "*Risk Factors – Hedging*".

## **Personnel**

As at December 31, 2023, the Corporation had 86 head office employees and 7 field employees.

## **Health, Safety and Environmental**

Management, employees and contractors are responsible and accountable for the Corporation's overall health, safety and environmental program. Surge 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.

Surge maintains a safe and environmentally responsible work place 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.

In 2023 Surge continued its commitment to environmental, social and governance spending initiatives by spending an aggregate of \$15.6 million on abandonment activities.

## **PRINCIPAL PRODUCING PROPERTIES**

The Corporation's principal oil and natural gas producing properties are located in Alberta and Saskatchewan and are focused across five core areas: Sparky, Southeast Saskatchewan, Carbonates, Valhalla and Shaunavon. The Corporation additionally holds interests in properties in Manitoba and certain other non-core areas in Alberta and Saskatchewan (referred to collectively as "**Minors**"). A description of each of these properties as at December 31, 2023 is provided below.

### **Sparky**

As at December 31, 2023, Surge's principal properties in the Sparky area included the Sparky assets and the Lloyd/Cummings waterfloods at Giltedge, Silver, and Provost. At Sparky, Surge held an average working interest of approximately 91 percent in approximately 80,855 gross (73,553 net) developed acres and an average working interest of approximately 97 percent in approximately 57,881 gross (55,996 net) undeveloped acres. As at December 31, 2023, the Corporation held interests in 759 gross (634 net) oil wells and 10 gross (9 net) gas wells producing from formations including, but not limited to, Sparky, Lloydminster, and Cummings. In addition, the Corporation operates multiple oil batteries, providing a strong infrastructure base for future development in the area. Surge's fourth quarter 2023 production in Sparky was approximately 11,275 boe/d (85 percent oil and NGLs).

The Sparky assets are located between Provost and Wainwright in eastern Alberta and western Saskatchewan. Provost and Betty Lake are early-stage primary development properties, while Wainwright, Giltedge, and Sounding Lake are more mature, mostly developed waterflood assets. Production from the Sparky assets is primarily crude oil (85 percent oil and NGLs) ranging from 19° to 28° API.

In 2023, the Corporation drilled 35 gross (35 net) horizontal Sparky oil wells. Of these wells, 31 were on production by year-end 2023 and the remaining wells came on production in Q1 2024.

## **Southeast Saskatchewan**

As at December 31, 2023, the Corporation's principal properties in the Southeast Saskatchewan area include but are not limited to the fields of, Viewfield, Minard, Steelman, Pinto, Bryant, Gainsborough, Freda Lake, and Neptune.

These Southeast Saskatchewan properties are primarily located in the Southeast corner of the province. As at December 31, 2023, these operated properties included an average working interest of approximately 85 percent in approximately 61,158 gross (52,263 net) developed acres and an average working interest of approximately 81 percent in 41,505 gross (33,780 net) undeveloped acres. As at December 31, 2023, the Corporation held interests in 354 gross (282 net) oil wells producing in the Midale, Frobisher, Alida, and Ratcliffe formations. The Corporation's production from this property is weighted 70 percent to light crude oil (greater than 31.1° API) and 30 percent to medium crude oil (22.3° to 31.1° API). The Corporation operates major facilities at this property providing a strong infrastructure base for future development in the area. This property's fourth quarter 2023 production was approximately 7,695 boe/d (94 percent oil).

In 2023, the Corporation drilled 35 gross (30 net) horizontal, Frobisher and Midale oil wells. Of these wells, 33 were on production by year-end 2023 and the remaining wells came on production in Q1 2024.

## **Carbonates**

As at December 31, 2023, Carbonates includes the Corporation's Greater Sawn, Nevis, and Westerosé properties. The Corporation's principal properties in the Greater Sawn area included Sawn Lake, Otter and Red Earth (which collectively comprise the Greater Sawn Lake assets). Within Carbonates, Surge held an average working interest of approximately 80 percent in approximately 138,814 gross (110,981 net) developed acres and an average working interest of approximately 77 percent in approximately 69,034 gross (53,016 net) undeveloped acres. As at December 31, 2023, the Corporation held interests in 435 gross (349 net) oil wells and 21 gross (16 net) gas wells producing from formations including, but not limited to, Slave Point, Granite Wash, Gilwood, Wabamun and Banff. In addition, the Corporation operates multiple oil batteries providing a strong infrastructure base for future development in the area. Surge's fourth quarter 2023 production in Carbonates was approximately 2,690 boe/d (91 percent oil and NGLs).

The Greater Sawn Lake assets are comprised of three main fields (Sawn Lake, Otter and Red Earth) near Red Earth Creek in Northern Alberta. Production from this property is primarily 40° API light oil from the Slave Point and Granite Wash formations. The majority of the new development is focused on the Slave Point formation. The majority of these pools are currently on primary production with horizontal Slave Point waterflood being implemented in Sawn Lake.

## **Valhalla**

As at December 31, 2023, the Corporation's principal property in the Valhalla area is the Valhalla/Wembley property. At Valhalla, Surge held an average working interest of approximately 70 percent in approximately 23,560 gross (16,598 net) developed acres and an average working interest of approximately 73 percent in approximately 10,520 gross (7,642 net) undeveloped acres. As at December 31, 2023, the Corporation held interests in 98 gross (59 net) oil wells and 13 gross (5 net) gas wells producing from formations including, but not limited to, Doig and Montney. In addition, the Corporation operates multiple oil batteries providing a strong infrastructure base for future development in the area. Surge's fourth quarter 2023 production in Valhalla was approximately 1,805 boe/d (47 percent oil and NGLs).

The Valhalla/Wembley property is located in northwestern Alberta, approximately 40 kilometres northwest of Grand Prairie. The majority of production from this property was from the horizontal oil wells producing from an extensive tight sand, with up to 40 metres of gross light oil pay in the Triassic Doig formation.

In 2023, the Corporation drilled one gross (0.5 net) horizontal, multi-frac, Doig oil well. This well was on production by December 31, 2023.

### **Shaunavon**

The Shaunavon properties are primarily located approximately 100 kilometres southwest of Swift Current, Saskatchewan and 140 kilometres east of the Alberta border. As at December 31, 2023, these operated properties included an average working interest of approximately 98 percent in approximately 25,206 gross (24,787 net) developed acres and an average working interest of 100 percent in 7,063 gross (7,063 net) undeveloped acres. As at December 31, 2023, the Corporation held interests in 181 gross (181 net) oil wells producing from the Upper and Lower Shaunavon formations, among others. The Corporation's production from this property is weighted 100 percent to medium crude oil (21° to 26° API). The Corporation operates major facilities at this property providing a strong infrastructure base for future development in the area. This property's fourth quarter 2023 production was approximately 935 boe/d (86 percent oil).

### **Manitoba**

As at December 31, 2023, the Corporation's principal properties in the Manitoba area included Sinclair.

The Manitoba properties are primarily located approximately 290 kilometres west of Brandon, Manitoba and east of the Saskatchewan border. As at December 31, 2023, these operated properties included an average working interest of approximately 68 percent in approximately 8,724 gross (5,956 net) developed acres and an average working interest of 100 percent in 1,506 gross (1,506 net) undeveloped acres. As at December 31, 2023, the Corporation held interests in 137 gross (75 net) oil wells producing from the Lodgepole, Bakken, and Torquay. The Corporation's production from this property is weighted 100 percent to medium crude oil (35° API). The Corporation operates major facilities at this property providing a strong infrastructure base for future development in the area. This property's fourth quarter 2023 production was approximately 470 boe/d (100 percent oil).

### **Minors**

As at December 31, 2023, the Corporation's principal properties include all of the non-core area across Alberta and Saskatchewan. In the minor areas, Surge held an average working interest of approximately 63 percent in approximately 109,957 gross (69,404 net) developed acres and an average working interest of approximately 55 percent in approximately 11,169 gross (6,139 net) undeveloped acres. As at December 31, 2023, the Corporation held interests in 101 gross (58 net) oil wells and 109 gross (29 net) gas wells. This area's fourth quarter 2023 production was approximately 175 boe/d (80 percent oil and NGLs).



## STATEMENT OF RESERVES DATA

In accordance with NI 51-101, Sproule prepared the Reserves Report based on its evaluation of the oil, NGLs and natural gas reserves attributable to the properties of the Corporation as at December 31, 2023. The Reserves Report has a preparation date of February 9, 2024.

The tables below are a combined summary of the oil, NGL and natural gas reserves attributable to the properties of the Corporation and the net present value of future net revenue attributable to such reserves as evaluated in the Reserves Report based on forecast price and cost assumptions. The tables summarize the data contained in the Reserves Report and, as a result, may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly.

The net present value of future net revenue attributable to reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures and well abandonment costs for only those wells assigned reserves by Sproule.

It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to reserves estimated by Sproule represent the fair market value of those reserves evaluated. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of oil, NGL and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein.

The Reserves Report is based on certain factual data supplied by the Corporation and Sproule's opinions of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to petroleum properties and contracts (except for certain information residing in the public domain) were supplied by the Corporation to Sproule. Sproule accepted this data as presented and neither title searches nor field inspections were conducted.

### Summary of Oil and Gas Reserves – Forecast Prices and Costs

	Gross Reserves					Net Reserves				
	Light and Medium Crude Oil (Mbbbls)	Heavy Crude Oil (Mbbbls)	Natural Gas Liquids (Mbbbls)	Conventional Natural Gas (MMcf)	Coalbed Methane (MMcf)	Light and Medium Crude Oil (Mbbbls)	Heavy Crude Oil (Mbbbls)	Natural Gas Liquids (Mbbbls)	Conventional Natural Gas (MMcf)	Coalbed Methane (MMcf)
<b>Proved</b>										
Developed Producing	26,580	10,396	888	29,695	-	22,775	9,086	763	27,084	-
Developed Non-Producing	949	654	64	1,639	-	821	595	54	1,450	-
Undeveloped	24,463	8,340	1,156	37,262	-	20,446	7,483	994	33,723	-
<b>Total Proved</b>	<u>51,992</u>	<u>19,390</u>	<u>2,108</u>	<u>68,596</u>	<u>-</u>	<u>44,042</u>	<u>17,164</u>	<u>1,811</u>	<u>62,257</u>	<u>-</u>
<b>Probable</b>	19,365	6,843	818	28,405	-	15,781	5,973	690	25,417	-
<b>Total Proved plus Probable</b>	<u>71,357</u>	<u>26,233</u>	<u>2,926</u>	<u>97,001</u>	<u>-</u>	<u>59,823</u>	<u>23,137</u>	<u>2,501</u>	<u>87,674</u>	<u>-</u>

## Net Present Value of Future Net Revenue – Forecast Prices and Costs

(\$M)	Before Future Income Tax Expenses and Discounted at				
	0%	5%	10%	15%	20%
<b>Proved</b>					
Developed Producing	1,015,046	966,369	857,915	765,643	692,314
Developed Non-Producing	64,888	52,749	44,205	37,928	33,150
Undeveloped	982,942	705,373	518,826	389,854	297,962
<b>Total Proved</b>	<b>2,062,876</b>	<b>1,724,491</b>	<b>1,420,946</b>	<b>1,193,425</b>	<b>1,023,426</b>
<b>Probable</b>	<b>1,237,698</b>	<b>858,896</b>	<b>638,112</b>	<b>497,782</b>	<b>402,538</b>
<b>Total Proved plus Probable</b>	<b>3,300,574</b>	<b>2,583,387</b>	<b>2,059,058</b>	<b>1,691,207</b>	<b>1,425,964</b>

(\$M)	After Future Income Tax Expenses and Discounted at				
	0%	5%	10%	15%	20%
<b>Proved</b>					
Developed Producing	1,015,046	966,369	857,915	765,643	692,314
Developed Non-Producing	64,888	52,749	44,205	37,928	33,150
Undeveloped	742,071	527,005	382,458	282,883	212,270
<b>Total Proved</b>	<b>1,822,005</b>	<b>1,546,123</b>	<b>1,284,578</b>	<b>1,086,454</b>	<b>937,734</b>
<b>Probable</b>	<b>950,986</b>	<b>653,121</b>	<b>482,424</b>	<b>375,277</b>	<b>303,256</b>
<b>Total Proved plus Probable</b>	<b>2,772,991</b>	<b>2,199,244</b>	<b>1,767,002</b>	<b>1,461,731</b>	<b>1,240,990</b>

	Unit Value before Income Tax Discounted at 10%/year (\$/boe)
<b>Proved</b>	
Developed Producing	23.10
Developed Non-Producing	25.82
Undeveloped	15.02
<b>Total Proved</b>	<b>19.36</b>
<b>Probable</b>	<b>23.92</b>
<b>Total Proved plus Probable</b>	<b>20.58</b>

## Additional Information Concerning Future Net Revenue – Forecast Prices and Costs (Undiscounted)

(Undiscounted) (\$M)	Revenue	Royalties	Operating Costs	Development Costs	Abandonment and Other Costs	Future net revenue before income taxes	Future income taxes	Future net revenue after income taxes
<b>Total Proved</b>	7,102,583	1,012,436	2,837,445	860,135	329,691	2,062,576	240,871	1,822,005
<b>Total Proved plus Probable</b>	<b>9,932,461</b>	<b>1,484,783</b>	<b>3,766,075</b>	<b>1,039,235</b>	<b>341,796</b>	<b>3,300,574</b>	<b>527,582</b>	<b>2,772,991</b>

## Future Net Revenue by Production Group – Forecast Prices and Costs

	Future Net Revenue Before Income Taxes and Discounted at 10% per year (\$M)	Per Unit Future Net Revenue Before Income Taxes and Discounted at 10% <sup>(3)</sup> per year (\$/boe)
<b>Proved</b>		
Light and Medium Crude Oil <sup>(1)</sup>	1,029,271	19.39
Heavy Crude Oil <sup>(1)</sup>	387,356	19.45
Conventional Natural Gas <sup>(2)</sup>	4,320	11.02
Coalbed Methane <sup>(2)</sup>	-	-
<b>Proved plus Probable</b>		
Light and Medium Crude Oil <sup>(1)</sup>	1,510,142	20.89
Heavy Crude Oil <sup>(1)</sup>	543,942	19.92
Conventional Natural Gas <sup>(2)</sup>	4,974	10.41
Coalbed Methane <sup>(2)</sup>	-	-

**Notes:**

1. Including solution gas and other by-products.
2. Including by-products, but excluding solution gas from oil wells.
3. Based on net reserves volumes.

**Pricing Assumptions – Forecast Prices and Costs**

Sproule employed the following pricing and inflation rate assumptions as of December 31, 2023 in its evaluation in estimating reserves data using forecast prices and costs. The weighted average historical prices received by the Corporation for 2023 are also reflected in the table below.

Year	Medium and Light Crude Oil		Natural Gas	NGL			Operating Cost Inflation rates (%/Yr)	Capital Cost Inflation rates (%/Yr)	Exchange rate (\$US/\$Cdn)
	Canadian Light Sweet Crude 40 API (\$/bbl)	Western Canada Select 20.5 API (\$/bbl)	Alberta AECO Gas Price (\$/MMBtu)	Edmonton Pentanes plus (\$/bbl)	Edmonton Butane (\$/bbl)	Edmonton Propane (\$/bbl)			
2023 (Historic)	99.87	79.53	2.64	102.80	45.62	29.59	4.8%	4.9%	0.74
2024	97.33	81.33	2.33	101.33	50.67	28.21	0.0%	0.0%	0.75
2025	97.25	84.67	3.64	101.33	50.67	33.03	2.0%	2.0%	0.75
2026	97.17	84.33	3.95	101.33	50.67	32.78	2.0%	2.0%	0.75
2027	99.12	86.02	4.03	103.36	51.68	33.44	2.0%	2.0%	0.75
2028	101.10	87.74	4.11	105.43	52.71	34.11	2.0%	2.0%	0.75
2029	103.12	89.50	4.19	107.54	53.77	34.79	2.0%	2.0%	0.75
2030	105.18	91.29	4.27	109.69	54.84	35.48	2.0%	2.0%	0.75
2031	107.29	93.11	4.36	111.88	55.94	36.19	2.0%	2.0%	0.75
2032	109.43	94.97	4.44	114.12	57.06	36.92	2.0%	2.0%	0.75
2033	111.62	96.87	4.53	116.40	58.20	37.66	2.0%	2.0%	0.75
Thereafter	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	2.0%	2.0%	0.75

**Reconciliation of Changes in Reserves**

The following table sets forth a combined reconciliation of the Corporation's gross reserves as at December 31, 2023, derived from the Reserves Report using forecast prices and cost estimates, reconciled to the gross reserves of the Corporation as at December 31, 2023.

	Light and Medium Crude Oil (Mbbbls)	Heavy Crude Oil (Mbbbls)	Natural Gas Liquids (Mbbbls)	Conventional Natural Gas (MMcf)	Coalbed Methane (MMcf)	Boe (Mboe)
<b>Proved</b>						
Balance at December 31, 2022	43,253	27,109	2,734	69,070	759	84,735
Product Type Transfer	-	-	-	-	-	-
Extensions and Improved Recovery <sup>(1)</sup>	2,236	584	87	1,337	-	3,130
Infill Drilling <sup>(2)</sup>	1,811	1,038	121	3,723	-	3,591
Technical Revisions <sup>(3)</sup>	9,365	(6,775)	(570)	1,993	(707)	2,235
Acquisitions	-	-	-	-	-	-
Dispositions <sup>(4)</sup>	(10)	(75)	(7)	(536)	-	(181)
Economic Factors <sup>(5)</sup>	227	75	-	185	-	333
Production <sup>(6)</sup>	(4,892)	(2,566)	(257)	(7,176)	(52)	(8,920)
<b>Balance at December 31, 2023</b>	<b>51,990</b>	<b>19,390</b>	<b>2,108</b>	<b>68,596</b>	<b>-</b>	<b>84,923</b>
<b>Probable</b>						
Balance at December 31, 2022	18,989	12,442	1,270	31,167	235	37,935
Product Type Transfer	(13)	-	(2)	(13)	-	(18)
Extensions and Improved Recovery <sup>(1)</sup>	869	642	21	1,066	-	1,709
Infill Drilling <sup>(2)</sup>	41	(526)	22	(2,007)	-	(798)
Technical Revisions <sup>(3)</sup>	(505)	(5,672)	(472)	(1,216)	(235)	(6,891)
Acquisitions	-	-	-	-	-	-

	Light and Medium Crude Oil (Mbbbls)	Heavy Crude Oil (Mbbbls)	Natural Gas Liquids (Mbbbls)	Conventional Natural Gas (MMcf)	Coalbed Methane (MMcf)	Boe (Mboe)
Dispositions <sup>(4)</sup>	(3)	(107)	(3)	(323)	-	(166)
Economic Factors <sup>(5)</sup>	(12)	63	(18)	(268)	-	(12)
Production <sup>(6)</sup>	-	-	-	-	-	-
<b>Balance at December 31, 2023</b>	<b>19,366</b>	<b>6,842</b>	<b>818</b>	<b>28,406</b>	<b>-</b>	<b>31,759</b>

	Light and Medium Crude Oil (Mbbbls)	Heavy Crude Oil (Mbbbls)	Natural Gas Liquids (Mbbbls)	Conventional Natural Gas (MMcf)	Coalbed Methane (MMcf)	Boe (Mboe)
<b>Proved plus Probable</b>						
Balance at December 31, 2022	62,244	39,552	4,004	100,237	993	122,671
Product Type Transfer	(13)	-	(2)	(13)	-	(18)
Extensions and Improved Recovery <sup>(1)</sup>	3,105	1,226	109	2,403	-	4,840
Infill Drilling <sup>(2)</sup>	1,852	512	143	1,716	-	2,793
Technical Revisions <sup>(3)</sup>	8,860	(12,446)	(1,043)	777	(941)	(4,656)
Acquisitions	-	-	-	-	-	-
Dispositions <sup>(4)</sup>	(13)	(182)	(9)	(859)	-	(347)
Economic Factors <sup>(5)</sup>	214	138	(17)	(83)	-	322
Production <sup>(6)</sup>	(4,892)	(2,566)	(257)	(7,176)	(52)	(8,920)
<b>Balance at December 31, 2023</b>	<b>71,357</b>	<b>26,234</b>	<b>2,928</b>	<b>97,002</b>	<b>-</b>	<b>116,685</b>

**Notes:**

- Includes the expansion or increased recovery factor for existing reservoirs as a result of additional step-out drilling or enhanced oil recovery associated with the Corporation's 2023 drilling program.
- Positive additions as a result of infill drilling within the Sparky and Southeast Saskatchewan areas.
- Technical revisions are due to changes in previously booked estimates. In 2023, these revisions were primarily: (1) positive revisions in Sparky and Southeast Saskatchewan core areas; (2) negative revisions in Greater Sawn (Carbonate) and Nevis (Carbonate) areas due to poor production performance and increased operating costs; (3) negative revisions in the Valhalla area due to production performance, decreased gas/oil ratio profiles, and decreased NGL yields.
- Reductions in volume estimates due to selling all or a portion of an interest in oil and gas properties. Dispositions occurred in the Corporation's minor central Alberta properties.
- The economic factors amount is the change in reserves due to changes in product pricing. The 2023 IQRE Average Forecast (being the average of forecasts by Sproule, McDaniel & Associates Consultants Ltd and GLJ Ltd.) was higher in all product types than was the 2022 IQRE Average Forecast.
- The Corporation averaged production of 24,438 boe/d in 2023..

**Additional Information Relating to Reserves Data**

***First Attributed Undeveloped Reserves***

The following table sets forth the volumes of proved undeveloped reserves that were first attributed in each of the three most recent financial years:

	Light and Medium Crude Oil (Mbbbls)	Heavy Crude Oil (Mbbbls)	Natural Gas Liquids (Mbbbls)	Conventional Natural Gas (MMcf)
<b>Proved</b>				
2021	5,576	2,529	472	5,355
2022	2,231	3,479	129	2,102
2023	2,946	788	143	2,141

The following table sets forth the volumes of probable undeveloped reserves that were first attributed in each of the three most recent financial years:

	<b>Light and Medium Crude Oil (Mbbls)</b>	<b>Heavy Crude Oil (Mbbls)</b>	<b>Natural Gas Liquids (Mbbls)</b>	<b>Conventional Natural Gas (MMcf)</b>
<b>Probable</b>				
2021	4,037	1,720	324	3,541
2022	1,871	2,651	133	3,725
2023	1,317	602	71	1,239

Proved undeveloped reserves are generally those reserves related to infill wells that have not yet been drilled or wells further away from gathering systems requiring relatively high capital to bring on production. Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. This also includes the probable undeveloped wedge from the proved undeveloped locations.

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

#### ***Significant Factors or Uncertainties Affecting Reserves Data***

The process of estimating reserves is 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 oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates made 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 governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices and reservoir performance. Such revisions can be either positive or negative.

#### ***Future Development Costs***

The table below sets out the combined total development costs deducted in the estimation in the Reserves Report of future net revenue attributable to proved reserves and proved plus probable reserves (using forecast prices and costs).

	Forecast Prices and Costs	
	Proved Reserves (\$M)	Proved plus Probable Reserves (\$M)
2024	130,085	137,915
2025	206,586	233,108
2026	207,671	237,249
2027	163,371	209,445
2028	117,093	209,445
Remaining Years	35,330	12,072
<b>Total Undiscounted</b>	<b>860,136</b>	<b>1,039,234</b>

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

## Other Oil and Gas Information

### Oil and Gas Wells

The following table sets forth the number and status of the wells comprising the Assets effective December 31, 2023.

	Active								Inactive							
	Oil		Natural Gas		Coalbed Methane		Water Inj/Disp		Oil		Natural Gas		Coalbed Methane		Water Inj/Disp	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	1,379	1,097	70	33	7	4	327	214	544	378	76	42	-	-	63	37
Saskatchewan	578	512	83	27	-	-	99	90	195	111	15	9	-	-	46	17
Manitoba	-	-	-	-	-	-	5	5	191	118	-	-	-	-	-	-
BC	-	-	1	1	-	-	-	-	-	-	-	-	-	-	-	-
<b>Total</b>	<b>1,957</b>	<b>1,609</b>	<b>154</b>	<b>61</b>	<b>7</b>	<b>4</b>	<b>431</b>	<b>309</b>	<b>930</b>	<b>607</b>	<b>91</b>	<b>51</b>	<b>-</b>	<b>-</b>	<b>109</b>	<b>54</b>

	Abandoned							
	Oil		Natural Gas		Coalbed Methane		Water Inj/Disp	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	1,494	1,245	339	244	1	1	231	190
Saskatchewan	153	106	624	602	-	-	16	7
Manitoba	7	7	-	-	-	-	-	-
BC	1	-	-	-	-	-	-	-
<b>Total</b>	<b>1,655</b>	<b>1,358</b>	<b>963</b>	<b>846</b>	<b>1</b>	<b>1</b>	<b>247</b>	<b>197</b>

### **Properties with no Attributed Reserves**

The following table summarizes, effective December 31, 2023, the gross and net acres of unproved properties in which the Corporation has an interest and also the number of net acres for which the Corporation's rights to explore, develop or exploit will, absent further action, expire within one year.

	<b>Gross Undeveloped Acres</b>	<b>Net Undeveloped Acres</b>	<b>Net Undeveloped Acres Expiring within One Year</b>
Alberta	144,987	118,848	20,223
Saskatchewan	61,828	49,072	4,601
Manitoba	1,506	1,506	905
BC	-	-	-
<b>Total</b>	<b>208,321</b>	<b>169,426</b>	<b>25,729</b>

### **Additional Information Concerning Abandonment and Reclamation Costs**

The Corporation typically estimates well abandonment costs area by area. Such costs are included in the Reserves Report as deductions in arriving at future net revenue. The expected total abandonment costs included in the Reserves Report for 5,096 net wells under the proved reserves category is \$329.7 million undiscounted (\$71.1 million discounted at 10 percent), of which a total of \$22.3 million is estimated to be incurred in 2025, 2026 and 2027. This estimate includes expected reclamation costs for surface leases which have existing wells with economic developed reserves assigned or future development drilling locations. The Corporation will be liable for its share of ongoing environmental obligations and for the ultimate reclamation of the properties held by it upon abandonment. Subject to pending changes in applicable regulations regarding the abandonment and reclamation, ongoing environmental obligations are expected to be funded out of cash flow.

### **Forward Contracts**

Surge is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments are used by Surge to reduce its exposure to fluctuations in commodity prices and foreign exchange rates. Surge is exposed to losses in the event of default by the counterparties to these derivative instruments. Surge manages this risk by diversifying its derivative portfolio amongst a number of financially sound counterparties.

For details of the Corporation's forward contracts in place as at December 31, 2023, see the Corporation's audited annual financial statements for the year ended December 31, 2023, which have been filed on SEDAR+ and may be viewed under the Corporation's profile at [www.sedarplus.com](http://www.sedarplus.com). See "Risk Factors – Hedging".

### **Tax Horizon**

Based on planned capital expenditures and the forecast commodity pricing employed in the Reserves Report, the Corporation estimates that it will not be required to pay current income taxes before 2026.

### **Costs Incurred**

The following table summarizes capital expenditures incurred by the Corporation during the year ended December 31, 2023.

	Property Acquisition Costs		Property Dispositions	Exploration Costs	Development Costs
	Proved Properties	Unproved Properties			
Total (\$M)	-	-	1,670	-	181,572

### Drilling Activity

The following table sets forth the gross and net exploration and development wells drilled by the Corporation based on rig release date during the year ended December 31, 2023.

	Exploration Wells		Development Wells	
	Gross	Net	Gross	Net
Light and Medium Crude Oil	-	-	70.00	64.49
Heavy Crude Oil	-	-	-	-
Conventional Natural Gas	-	-	-	-
Service	-	-	-	-
Dry	-	-	-	-
<b>Total</b>	-	-	70.00	64.49

### Planned Capital Expenditures

The Corporation has announced a planned capital expenditure budget of approximately \$190 million for 2023.

### Production Estimates

The following table discloses for each product type the total volume of production estimated by Sproule in the Reserves Report for 2023 in the estimates of future net revenue from gross proved and gross proved plus probable reserves disclosed above.

	Light and Medium Crude Oil (bbls/d)	Heavy Crude Oil (bbls/d)	Conventional Natural Gas (Mcf/d)	Coalbed Methane (Mcf/d)	Natural Gas Liquids (bbls/d)	Boe (boe/d)	%
<b>Proved</b>							
Carbonates	2,298	-	962	-	48	2,507	10%
Valhalla	785	-	5,549	-	108	1,818	8%
Sparky	7,657	841	9,770	-	133	10,259	43%
Shaunavon	-	717	701	-	17	851	3%
SE Saskatchewan	7,192	-	3,369	-	399	8,152	34%
Manitoba	436	-	-	-	-	436	2%
Minors	59	10	62	-	4	83	-
<b>Total Proved</b>	<b>18,427</b>	<b>1,568</b>	<b>20,413</b>	<b>-</b>	<b>709</b>	<b>24,106</b>	<b>100%</b>
<b>Proved Plus Probable</b>							
Carbonates	2,332	-	1,005	-	50	2,549	10%
Valhalla	820	-	5,799	-	113	1,900	7%
Sparky	8,173	965	10,339	-	141	11,001	42%
Shaunavon	-	743	729	-	18	882	3%
SE Saskatchewan	8,180	-	3,917	-	475	9,308	36%
Manitoba	465	-	-	-	-	465	2%
Minors	55	15	63	-	4	84	-
<b>Total Proved Plus Probable</b>	<b>20,025</b>	<b>1,723</b>	<b>21,852</b>	<b>-</b>	<b>801</b>	<b>26,189</b>	<b>100%</b>



## Production History

The following table discloses, on a quarterly basis for the year ended December 31, 2023, certain information in respect of production, product prices received, royalties paid, operating expenses and resulting operating netback for the Corporation.

### Average Daily Production Volume

	Three Months Ended			
	Mar 31, 2023	Jun 30, 2023	Sep 30, 2023	Dec 31, 2023
Conventional Natural Gas (Mcf/d)	20,172	18,458	19,564	21,005
Light and Medium Crude Oil (bbls/d)	21,055	19,758	20,188	20,741
NGL (bbls/d)	721	629	659	808
Coalbed Methane (Mcf/d)	179	110	131	153
<b>Total (boe/d)</b>	<b>25,168</b>	<b>23,482</b>	<b>24,129</b>	<b>25,075</b>

### Prices Received, Royalties Paid, Production Costs and Operating Netback – Crude Oil

(\$ per Bbl)	Three Months Ended			
	Mar 31, 2023	Jun 30, 2023	Sep 30, 2023	Dec 31, 2023
Prices Received	71.07	72.49	82.81	72.74
Royalties Paid	(12.79)	(12.25)	(15.07)	(13.59)
Production Costs	(22.10)	(21.42)	(20.68)	(19.76)
Transportation Costs	(1.79)	(1.58)	(1.31)	(1.48)
<b>Operating Netback<sup>(1)</sup></b>	<b>34.39</b>	<b>37.24</b>	<b>45.75</b>	<b>37.91</b>

**Note:**

- Including solution gas and associated natural gas liquids revenue.

### Prices Received, Royalties Paid, Production Costs and Operating Netback – Conventional Natural Gas

(\$ per Mcf)	Three Months Ended			
	Mar 31, 2023	Jun 30, 2023	Sep 30, 2023	Dec 31, 2023
Prices Received	3.13	1.97	2.15	2.11
Royalties Received	(0.32)	0.84	0.12	0.25
Production Costs	(0.94)	(0.98)	(0.87)	(0.87)
Transportation Costs	-	(0.05)	0.02	(0.01)
<b>Operating Netback</b>	<b>1.87</b>	<b>1.78</b>	<b>1.42</b>	<b>1.48</b>

### Prices Received, Royalties Paid, Production Costs and Operating Netback – Combined

(\$ per boe)	Three Months Ended			
	Mar 31, 2023	Jun 30, 2023	Sep 30, 2023	Dec 31, 2023
Prices Received	71.59	72.82	83.17	73.09
Royalties Paid	(12.84)	(12.11)	(15.05)	(13.55)
Production Costs	(22.26)	(21.58)	(20.82)	(19.90)
Transportation Costs	(1.79)	(1.59)	(1.31)	(1.48)
<b>Operating Netback<sup>(1)</sup></b>	<b>34.70</b>	<b>37.54</b>	<b>45.99</b>	<b>38.16</b>

**Note:**

- Operating Netback is calculated by deducting royalties paid and production costs, including transportation costs, from prices received, excluding the effects of hedging.

### **Production Volume by Field**

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

<b>Field</b>	<b>Light and Medium Crude Oil (bbls/d)</b>	<b>Conventional Natural Gas (Mcf/d)</b>	<b>Natural Gas Liquids (bbls/d)</b>	<b>Coalbed Methane (Mcf/d)</b>	<b>Boe (boe/d)</b>	<b>%</b>
Greater Sawn	2,516	1,448	77	-	2,834	12%
Valhalla	679	5,427	108	-	1,691	7%
Sparky	9,153	9,536	156	-	10,899	44%
Shaunavon	871	795	16	-	1,020	4%
Minors	145	138	8	143	199	1%
SE Saskatchewan	6,543	2,312	337	-	7,265	30%
Manitoba	527	1	2	-	530	2%
<b>Total</b>	<b>20,434</b>	<b>19,657</b>	<b>704</b>	<b>143</b>	<b>24,438</b>	<b>100%</b>

## DESCRIPTION OF CAPITAL STRUCTURE

### Share Capital

The Corporation is authorized to issue an unlimited number of Common Shares and an unlimited number of preferred shares, issuable in series. The following is a summary of the rights, privileges, restrictions and conditional attributed to the Common Shares, preferred shares and Debentures.

#### *Common Shares*

The holders of Common Shares are entitled to: (i) one vote for each Common Share held at all meetings of shareholders of the Corporation other than meetings of the holders of any class or series of shares meeting as a class or series; (ii) receive any dividends declared by the Corporation on the Common Shares; and (iii) subject to the rights of shares ranking prior to the Common Shares, to receive the remaining property of the Corporation on dissolution, after the payment of all liabilities.

#### *Preferred Shares*

Preferred shares may be issued in one or more series. The Board of Directors is authorized to fix the number of shares in each series and to determine the designation, rights, privileges, restrictions and conditions attached to the shares of each series. Preferred shares of the Corporation are entitled to a priority over the Common Shares with respect to the payment of dividends and the distribution of assets upon the liquidation, dissolution or winding-up of the Corporation.

#### **Debentures**

The Debentures were issued under and pursuant to the provisions of the Indenture between Computershare Trust Company of Canada, as trustee, and the Corporation.

The following is a summary of the material attributes and characteristics of the outstanding Debentures. This summary does not purport to be complete and is subject to and qualified in its entirety by reference to the terms of the Indenture which may be viewed under Surge's profile on SEDAR+ at [www.sedarplus.com](http://www.sedarplus.com).

The Debentures are direct, subordinated, unsecured obligations of the Corporation, subordinated to any existing and future senior indebtedness of the Corporation and ranking equally with one another and with all other existing and future subordinated unsecured indebtedness of the Corporation to the extent subordinated on the same terms.

The Debentures will mature and be repayable on December 31, 2028 (the "**Maturity Date**") and will accrue interest at the rate of 8.50% per annum payable semi-annually in arrears on December 31 and June 30 of each year (each a "**Interest Payment Date**"), commencing on June 30, 2024 and computed on the basis of a 365-day year. Interest on the Debentures will be payable in lawful money of Canada.

At the holder's option, the Debentures may be converted into Common Shares at any time prior to 5:00 p.m. (Calgary time) on the earlier of (i) the business day immediately preceding the Maturity Date; or (ii) if the Debentures are called for redemption, on the business day immediately preceding the date (the "**Redemption Date**") specified by the Corporation for redemption of the Debentures, in each case, at a conversion price of \$13.25 per Common Share, representing a conversion rate of approximately 75.4717 Common Shares per \$1,000 principal amount of Offered Debentures, subject to adjustment in accordance with the Indenture. Holders who convert their Debentures will receive, in addition to the applicable number of Common Shares, accrued and unpaid interest in respect thereof for the period up to, but excluding, the date of conversion from, and including, the most recent Interest Payment Date. If a holder elects to convert

its Debentures in connection with a change of control that occurs prior to the Maturity Date, the holder will be entitled to receive additional Common Shares as a make-whole premium on conversion in certain circumstances (as more fully described in the Indenture).

The Debentures will not be redeemable by the Corporation prior to December 31, 2026, except in certain limited circumstances following a change of control. On, and after, December 31, 2026 and prior to December 31, 2027, the Debentures may be redeemed by the Corporation, subject to certain restrictions, in whole or in part from time to time, on not more than 60 days', and not less than 30 days', prior written notice, at a redemption price equal to the principal amount thereof plus accrued and unpaid interest thereon, if any, up to but excluding the date set for redemption, provided that the Current Market Price on the date on which notice of redemption is given is not less than 125% of the Conversion Price. On or after December 31, 2027 and prior to the Maturity Date, the Debentures may be redeemed by the Corporation, subject to certain restrictions, in whole or in part from time to time, on not more than 60 days', and not less than 30 days', prior written notice, at a redemption price equal to the principal amount thereof plus accrued and unpaid interest thereon, if any, up to but excluding the date set for redemption.

On the Redemption Date or the Maturity Date, as applicable, subject to required regulatory approvals and provided that no event of default (as provided in the Indenture) has occurred and is continuing, the Corporation may, at its option, on not more than 60 days', and not less than 30 days', prior notice, elect to satisfy its obligation to repay, in whole or in part, the principal amount of the Debentures which are to be redeemed or which have matured by issuing and delivering freely tradeable Common Shares to the holders of the Debentures. Payment for which the Corporation elects to repay in Common Shares would be satisfied by delivering that number of Common Shares obtained by dividing the principal amount of the Debentures by 95% of the Current Market Price of the Common Shares on the Redemption Date or Maturity Date, as applicable. Any accrued and unpaid interest will be paid in cash.

The Debentures are listed and posted for trading on the TSX under the symbol "SGY.DB.B".

### **DIVIDEND POLICY**

The Credit Facilities contain certain restrictions on Surge's ability to pay dividends. In addition, the payment of dividends by a corporation is governed by the liquidity and insolvency tests described in the ABCA. Pursuant to the ABCA, after the payment of a dividend, a corporation must be able to pay its liabilities as they become due and the realizable value of the assets of the corporation must be greater than the liabilities and the legal stated capital of its outstanding securities.

The following monthly cash dividends on Common Shares were declared in respect of the periods indicated:

<b>Month</b>	<b>Dividends per Common Share (\$)</b>		
	<b>2023</b>	<b>2022</b>	<b>2021</b>
January	0.04	-	-
February	0.04	-	-
March	0.04	-	-
April	0.04	-	-
May	0.04	-	-
June	0.04	0.035	-
July	0.04	0.035	-
August	0.04	0.035	-
September	0.04	0.035	-
October	0.04	0.035	-

<b>Month</b>	<b>Dividends per Common Share (\$)</b>		
	<b>2023</b>	<b>2022</b>	<b>2021</b>
November	0.04	0.035	-
December	0.04	0.035	-
<b>Total</b>	<b>0.48</b>	<b>0.245</b>	<b>-</b>

Unless otherwise specified, all dividends paid are designated as "eligible dividends" under the *Income Tax Act* (Canada).

The amount of future cash dividends, if any, will be subject to the discretion of the Board of Directors and will otherwise depend on a variety of factors, including the removal of the restrictions on the payment of dividends contained in the Credit Facilities, prevailing economic and competitive environment, results of operations, fluctuations in working capital, the price of oil and gas, the taxability of the Corporation, the Corporation's ability to raise capital, the amount of capital expenditures, the satisfaction of solvency tests imposed by the ABCA for the declaration and payment of dividends, applicable law and other factors. See "*Risk Factors*".

#### MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSX under the trading symbol "SGY". The following table sets forth the market price ranges and the trading volumes for the Common Shares for the periods indicated, as reported by the TSX, for the year ended December 31, 2023.

<b>Period</b>	<b>Price Range (\$)</b>		<b>Trading Volume</b>
	<b>High</b>	<b>Low</b>	
January	9.89	8.07	11,031,893
February	9.76	8.34	16,311,875
March	9.45	7.72	15,157,684
April	9.64	8.53	8,312,660
May	8.76	7.41	11,036,495
June	8.03	6.68	7,458,033
July	8.32	6.90	6,769,859
August	8.85	7.82	8,973,580
September	9.65	8.37	10,396,513
October	9.75	8.19	11,585,144
November	9.77	7.665	12,407,685
December	7.76	6.17	17,393,634

The Debentures are listed and posted for trading on the TSX under the trading symbol "SGY.DB.B". The following table sets forth the market price ranges and the trading volumes for the Debentures for the periods indicated, as reported by the TSX, for the year ended December 31, 2023.

Period	Price Range (\$)		Trading Volume
	High	Low	
January	-	-	-
February	-	-	-
March	-	-	-
April	-	-	-
May	-	-	-
June	-	-	-
July	-	-	-
August	-	-	-
September	-	-	-
October 19 to 31	104.94	101.05	1,089,000
November	103.50	100.80	6,141,000
December	102.00	101.55	366,000

**Note:**

(1) The Debentures were issued and commenced trading on the TSX on October 19, 2023.

### DIRECTORS AND OFFICERS

The name, municipality of residence, principal occupation for the prior five years and position with the Corporation of each of the directors and executive officers of the Corporation are as follows:

Name and Residence	Position	Principal Occupation During Previous Five Years
Paul Colborne Alberta, Canada	President and Chief Executive Officer  Director since April 13, 2010	President and Chief Executive Officer of the Corporation. He is also the President of Star Valley Oil and Gas Ltd., a private Calgary-based oil and gas company. In 1993, after nine years practicing securities, banking, and oil and gas law, Mr. Colborne directed his focus to the oil and gas industry and founded Startech Energy Ltd., a publicly traded company which grew to 15,000 boepd. In 2001, Startech was acquired by ARC Energy Trust for more than \$500 million. From 2003 to 2005, Mr. Colborne was the President and Chief Executive Officer of StarPoint Energy Trust, a 36,000 boepd publicly traded energy trust. From 1996 to 2013, Mr. Colborne was on the Board of Directors of Crescent Point Energy Corp., a 110,000 boepd publicly traded oil and gas company. In 2014, Paul stepped down from the Board of Legacy Oil & Gas and completed his term as Chairman of New Star Energy Ltd. He served as Chairman of Rising Star Resources Ltd. until its sale in 2022. He was also previously on the Board of Directors of Westfire Energy Ltd., Twin Butte Energy Ltd., Red River Oil Inc., Cequence Energy Ltd., Seaview Energy Ltd., Breaker Energy Ltd., Mission Oil and Gas Inc., and TriStar Oil & Gas Ltd.
James Pasiaka Alberta, Canada	Director since April 13, 2010	Counsel to the national law firm McCarthy Tétrault LLP from January 1, 2020 to August 31, 2023. Prior thereto, partner at McCarthy Tétrault LLP since September 1, 2013. Prior to that, partner of the national law firm Heenan Blaikie LLP since January 1, 2001. Mr. Pasiaka has served as an officer and

<b>Name and Residence</b>	<b>Position</b>	<b>Principal Occupation During Previous Five Years</b>
	Chairman of the Board since January 7, 2015	director of a number of public energy companies, and chairman of the board of several oil and gas companies.
Marion Burnyeat ICD.D <sup>(2)(4)</sup> Alberta, Canada	Director since July 16, 2018	Chair of the Compensation, Nominating and Corporate Governance Committee for the Corporation. Director, Calgary Academy and Headwater Learning Group since June 2018. Prior thereto, Director, SECURE Energy Services from April 2020 to July 2021. Consultant with Inter Pipeline Ltd. on mergers and acquisitions from April to June 2018. Vice President of Field Services at Westcoast Energy Inc. from January 2013 to March 2017. Prior thereto, Ms. Burnyeat served as Vice President of Midstream of Westcoast Energy Inc. from May 2008 to January 2013. She served as Vice President Strategic Development and Stakeholder Relations at Westcoast Energy Inc. from January 2007 to May 2008. Ms. Burnyeat has nearly 30 years experience in the energy sector primarily with Spectra Energy Corporation and its predecessor companies. She held increasingly responsible executive roles in leading Midstream business units, Strategic Development, Stakeholder Relations and Business Development. Ms. Burnyeat holds the ICD.D designation from the Institute of Corporate Directors, a Bachelor of Commerce degree from the University of Alberta and a Master of Business Administration degree from Edinburgh University, Scotland. She has held positions on not-for-profit boards and is an active volunteer for several charitable organizations including Freestyle Alberta.
Daryl Gilbert <sup>(3)(4)</sup> Alberta, Canada	Director since June 5, 2014	Chair of the Environment, Health and Safety Committee for the Corporation. Managing Director and Investment Committee member of Carbon Infrastructure Partners (formerly JOG Capital Inc. (" <b>JOG Capital</b> ")) since May 2008. Mr. Gilbert has also been an independent businessman and investor, and serves as a director for a number of public and private entities, since 2005. Mr. Gilbert has been active in the Western Canadian oil and natural gas sector for over 40 years, working in reserves evaluation with Gilbert Laustsen Jung Associates Ltd. (now GLJ Petroleum Consultants Ltd. (" <b>GLJ</b> ")), an engineering consulting firm, from 1979 to 2005. Mr. Gilbert served as President and Chief Executive Officer of GLJ from 1994 to 2005.
Michelle Gramatke <sup>(1)(2)(3)</sup> Alberta, Canada	Director since May 2019	Ms. Gramatke is a Chartered Professional Accountant with over 25 years of financial experience. She has most recently acted as Chief Financial Officer of JOG Capital (a private equity investment firm based in Calgary) from 2004 until August 2020. Prior to her position with JOG Capital, Ms. Gramatke held several executive positions, including as Chief Financial Officer of PricewaterhouseCoopers Central Asia, Deputy Chief Financial Officer for an American NASDAQ-listed telecommunications company with operations in Russia and Manager with PricewaterhouseCoopers Moscow. Ms. Gramatke began her career with KPMG in Calgary focusing on Canadian upstream oil and gas, construction and mining companies.
Robert Leach <sup>(1)(2)</sup> Arizona, United States of America	Director since April 13, 2010	President of Sonoma Valley LLC Arizona Inc., a Phoenix based real estate investment company. Mr. Leach was formerly Chief Executive Officer of Custom Truck Sales Ltd., a private company operating Kenworth truck dealerships in Saskatchewan and Manitoba since 1986.

<b>Name and Residence</b>	<b>Position</b>	<b>Principal Occupation During Previous Five Years</b>
Allison Maher <sup>(1)(2)(3)</sup> Alberta, Canada	Director since July 16, 2018	Chair of the Audit Committee. President, Director and Co-founder of Family Wealth Coach Planning Services since January 2009. Prior thereto, Ms. Maher worked at other financial-advisory and estate-planning companies such as Great-West Life (London Life) for a decade. Ms. Maher began her career at KPMG in the areas of Tax and Corporate Audit. Ms. Maher has her Certified Corporate Director, Chartered Professional Accountant, Certified Financial Planner, Trust and Estate Practitioner and Family Enterprise Advisor designations. Ms. Maher received her Bachelor of Commerce degree, with Distinction, from the University of Calgary. Ms. Maher is an active member of the Institute of Corporate Directors, Chair of TIGER21 Calgary and currently holds board positions on several not-for-profit boards.
P. Daniel O'Neil <sup>(3)(4)</sup> Alberta, Canada	Director since April 13, 2010	Chair of the Reserves Committee for the Corporation. Independent businessperson since his retirement on May 8, 2013. Prior thereto, Mr. O'Neil had acted as President and Chief Executive Officer of the Corporation from April 13, 2010 until his retirement and as President and Chief Executive Officer of Breaker Energy Ltd., a publicly traded oil and natural gas company, from its formation in September 2004 until its acquisition by NAL Oil & Gas Trust in December 2009. Mr. O'Neil was also a director of Cathedral Energy Services Ltd. Prior to their sales, Mr. O'Neil was acted as a Director of Hyperion Exploration Corporation and Cequence Energy Ltd.
Murray Smith <sup>(2)(4)</sup> Alberta, Canada	Director since June 25, 2010	President of Murray Smith and Associates. Mr. Smith also serves on the board of two private companies and Williams Companies Inc. (WMB.nyse), a Tulsa based midstream company. Prior thereto, Mr. Smith acted as an Official Representative of the Province of Alberta to the United States of America until 2007.  Prior thereto, Mr. Smith was a member of the Legislative Assembly in the Province of Alberta serving in four different Cabinet portfolios – Energy, Gaming, Labour, and Economic Development from 1993 to 2005.
Murray Bye Alberta, Canada	Chief Operating Officer	Chief Operating Officer of the Corporation since August 2018. Prior thereto, Mr. Bye acted as Vice President, Production of the Corporation from May 2013. Prior thereto, Mr. Bye was Asset Team Lead – West at Surge since June 2010. Prior to his role at Surge, Mr. Bye held a number of positions at EnCana Corporation between the years 2000 to 2010 including: Group Lead of Development, Exploitation Engineer, and Production Engineer. Mr. Bye received a Petroleum Engineering degree from Montana Tech.
Jared Ducs Alberta, Canada	Chief Financial Officer	Chief Financial Officer of the Corporation since August 2019. Prior thereto, Mr. Ducs has held several progressively more senior roles at the Corporation including Director of Corporate Development, Assistant Controller and Manager of Financial Reporting and, most recently, held the position of Vice President, Finance of the Corporation since August 2018. Preceding his role at the Corporation, Mr. Ducs was a senior member of the Finance group at Breaker Energy Ltd. prior to its sale to NAL Oil & Gas Trust in 2009. Prior thereto, Mr. Ducs was a senior associate with Ernst & Young LLP. Mr. Ducs holds a Chartered Accountant Designation and received his Bachelor of Management in Accounting and Finance from the University of Lethbridge.
Derek Christie Alberta, Canada	Senior Vice President –	Senior Vice President, Exploration of the Corporation since January 2024. Prior thereto, Mr. Christie held the position of Senior Vice President, Geosciences of the Corporation from November 2019. Prior thereto, Mr.



<b>Name and Residence</b>	<b>Position</b>	<b>Principal Occupation During Previous Five Years</b>
	Geosciences	Christie acted as the Senior Vice President of Exploration & Corporate Development at Crescent Point Energy and was previously employed with Crescent Point Energy in various Senior Management positions in exploration, geosciences and corporate development since February 2007.
Margaret Elekes Alberta, Canada	Senior Vice-President, Land and Business Development	Senior Vice-President, Land and Business Development of the Corporation since August 2018. Prior thereto, Ms. Elekes held the position of Vice-President, Land and Business Development of the Corporation from August 2016. Prior thereto and since April 2010, Ms. Elekes acted as Vice-President, Land of the Corporation at Surge.

**Notes:**

1. Member of the Audit Committee.
2. Member of the Compensation, Nominating and Corporate Governance Committee of the Board.
3. Member of the Reserves Committee of the Board.
4. Member of the Environment, Health and Safety Committee of the Board.

As at March 6, 2024, the directors and executive officers of the Corporation, as a group, beneficially own, control or direct, directly or indirectly, 2,803,201 Common Shares, representing approximately 2.8 percent of the outstanding Common Shares.

The terms of office of each of the directors of the Corporation will expire at the next annual general meeting of the shareholders of the Corporation.

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

Other than as set forth below, to the knowledge of management of the Corporation:

- a) no director or executive officer of the Corporation is, or within the 10 years before the date of this AIF, has been, a director, chief executive officer or chief financial officer of any other issuer that: (i) was the subject of a cease trade or similar order or an order that denied the other issuer access to any exemptions under Canadian securities legislation that lasted for a period of more than 30 consecutive days that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (ii) was subject to a cease trade or similar order or an order that denied the relevant issuer access to any exemption under securities legislation that lasted for a period of more than 30 consecutive days 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 the person was acting in the capacity as director, chief executive officer or chief financial officer;
- b) no director or executive officer, or any shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, or a personal holding company of any such person: (i) is, at the date of this AIF or has been within the 10 years before the date of this AIF, a director or executive officer of any company that, while that person was acting in that capacity or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (ii) has, within the 10 years before the date of this AIF, become 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 the assets of the director, officer or shareholder; and

- c) no director or executive officer, or any shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, has: (i) been subject to any penalties or sanctions imposed by a court relating to Canadian securities legislation or by a Canadian securities regulatory authority or has entered into a settlement agreement with the Canadian securities regulatory authority; or (ii) been subject to 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.

Mr. Gilbert was a director of LGX Oil and Gas Inc. ("**LGX**"), a public oil and gas company, from August 2013 until June 2016. On June 7, 2016 a consent receivership order was granted by the Alberta Court of King's Bench (the "**Court**") upon an application by LGX's senior lender. LGX's stock was cease traded shortly thereafter and a receiver manager was appointed. Mr. Gilbert was a director of Connacher Oil & Gas Limited ("**Connacher**") from October 2014 until February 2019. On May 17, 2016, Connacher applied for and was granted protection from its creditors by the Court pursuant to the *Companies' Creditors Arrangement Act* (Canada). On February 16, 2019, Connacher announced that it was proceeding to close on a credit bid transaction with its supporting lenders. Mr. Gilbert resigned from the Board shortly thereafter. Mr. Gilbert was a director of Trident Exploration Corp. ("**Trident**") from 2010 through year end 2018. On April 30, 2019, Trident announced it had ceased operations and had transferred all assets to the Alberta Energy Regulator. On May 3rd, 2019, PricewaterhouseCoopers LLP was appointed receiver.

Mr. Pasiaka was also a director of LGX. Mr. Pasiaka resigned as a director of LGX in July 2015. LGX was placed into receivership nearly twelve months later in June 2016 and, in connection therewith, a receiver was appointed under the *Bankruptcy and Insolvency Act* (Canada). Cease trade orders in respect of LGX were issued shortly after the appointment of the receiver.

Mr. O'Neil was a director of Cequence Energy Ltd. ("**Cequence**") from March 2019 to May 2020. On May 29, 2020, Cequence announced that it had commenced a strategic process to identify and pursue potential strategic options and alternatives to maximize the value for its stakeholders, to be carried out under the CCAA and that it had on obtained an initial order (the "**Initial Order**") from the Court commencing proceedings under the CCAA on that same date. Mr. O'Neil tendered his resignation as a director of Cequence prior to Cequence obtaining the Initial Order. Based on publicly available information, on September 28, 2020, Cequence announced that the implementation of a plan of compromise and arrangement under the CCAA had been sanctioned on September 17, 2020 by order of the Court.

### **Conflicts of Interest**

As at the date hereof, the Corporation is not aware of any existing or potential material conflicts of interest between the Corporation and a director or officer of the Corporation.

## **AUDIT COMMITTEE**

### **Composition of the Audit Committee, Charter and Review of Services**

The Audit Committee of the Board of Directors operates under a written charter that sets out its responsibilities and composition requirements. A copy of the charter is attached to this AIF as Schedule "C".

The members of the Audit Committee of the Board of Directors are Allison Maher (Chair), Robert Leach and Michelle Gramatke. The Audit Committee charter requires all members of the Audit Committee to be

"financially literate" and "independent" within the meaning of applicable securities laws. All members of the Audit Committee meet these requirements. The relevant education and experience of each Audit Committee member is outlined below:

<u>Name</u>	<u>Independent</u>	<u>Financially Literate</u>	<u>Relevant Education and Experience</u>
Allison Maher	✓	✓	<p>Ms. Maher is currently the President and Director of her own advisory firm, Family Wealth Coach Planning Services. She is highly involved in matters related to succession planning, as well as family governance, estate and risk management. Ms. Maher began her career with KPMG in the areas of Tax and Corporate Audit.</p> <p>Ms. Maher is presently a member of the Chartered Professional Accountants of Alberta, as well as an active member of the Institute of Corporate Directors, Chair of TIGER21 Calgary and currently holds board positions on several not-for-profit boards. Ms. Maher also holds Certified Corporate Director and Certified Financial Planner designations.</p> <p>Ms. Maher was a member of the board of the Calgary Health Foundation from February 2020 to April 2023 and was a member of the board of the Heritage Park Foundation since June 2014 to June 2020. Ms. Maher has been a trustee for the Cidel Donor Advised Fund since June 2014. From May 2011 to May 2017, she served as chairperson and advisory board member for the Alberta Business Family Institute (University of Alberta).</p> <p>Ms. Maher holds a Bachelor of Commerce degree, with Distinction, from the University of Calgary.</p>
Robert Leach	✓	✓	<p>Mr. Leach is currently the President of Sonoma Valley LLC Arizona Inc., a Phoenix based real estate investment company. Mr. Leach was formerly the Chairman of the board of Breaker Energy Ltd. and holds a Bachelor of Commerce degree, majoring in accounting, from the University of Saskatchewan.</p> <p>Mr. Leach has experience reviewing and assessing financial statements from his tenure on the audit committee of Breaker, as a member of the Board of Surge, and through his years of experience at Custom Truck Sales Ltd. and International Fitness Holdings.</p>
Michelle Gramatke	✓	✓	<p>Ms. Gramatke was Chief Financial Officer and Chief Compliance Officer of JOG Capital, a Calgary based private equity investment fund advisor which invests in Canadian oil &amp; gas companies from 2004 to August 2020. Ms. Gramatke was responsible for JOG Capital's financial reporting, treasury, tax and regulatory compliance. Ms. Gramatke is presently a member of the Chartered Professional Accountants of Alberta and holds a Bachelor of Management degree from the University of Lethbridge.</p>

## Pre-Approval of Policies and Procedures

The Audit Committee provides that the Audit Committee must pre-approve all non-audit services to be provided to the Corporation or its subsidiaries by external auditors. The Audit Committee has delegated to the Chair of the Audit Committee the authority to pre-approve non-audit services, provided that the Chair reports to the Audit Committee at the next scheduled meeting and such pre-approval and the Chair comply with such other procedures as may be established by the Audit Committee from time to time. The Audit Committee also pre-approves all audit services and the fees to be paid.

## External Auditor Service Fees

KPMG LLP are the auditors of the Corporation. KPMG LLP have been the auditors of the Corporation since May 5, 2010.

The following table sets out the aggregate fees billed by KPMG LLP to the Corporation in each of the last two fiscal years.

<u>Year</u>	<u>Audit Fees<sup>(1)</sup></u>	<u>Audit-Related Fees</u>	<u>Tax Fees<sup>(2)</sup></u>	<u>All Other Fees</u>
2023	\$428,000	\$nil	\$91,325	\$74,900
2022	\$395,900	\$nil	\$281,888	\$118,770

**Notes:**

1. Audit fees consist of fees for the audit of annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements. The services provided in this category included quarterly review fees.
2. Fees for tax compliance, tax advice and tax planning.

## INDUSTRY CONDITIONS

Companies carrying on business in the petroleum and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government and, with respect to the pricing and taxation of crude oil and natural gas, through legislation enacted by, and agreements among, the federal and provincial governments of Canada, all of which should be carefully considered by investors in the Canadian petroleum and natural gas industry. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. While such regulations 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 legislation, regulations and agreements carefully.

## Pricing and Marketing in Canada

### *Crude Oil*

Producers of crude oil are entitled to negotiate sales contracts directly with crude oil 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, but regional market and transportation issues also influence prices. The specific price that a producer receives will depend, in part, on crude oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, supply/demand balance, and contractual terms of sale.

Following the COVID-19 pandemic, the oil markets began to rebalance in 2021 with oil prices reaching their highest levels in six years. The rebound continued into 2022 with a surge in oil prices in early 2022. This was primarily driven by the impact of the Russian invasion of Ukraine and the OPEC+ decision to adhere

to previously agreed-upon production cuts. Additionally, the global economic conditions and outlook improved due to reducing and easing COVID-19 restrictions. In June 2023, OPEC+ made a deal to target lower oil supply up until the end of 2024 in order to stabilize the price of oil. In anticipation of a potential surplus, in November 2023, OPEC+ producers agreed to a voluntary cut in output for the first quarter of 2024.

While the trajectory of oil prices continue to be subject to uncertainty and volatility, factors such as transportation disruptions, supply constraints and conflict in Ukraine continue to be unpredictable and may have an ongoing impact on oil demand and prices. See "*Risk Factors – Exposure to Widespread Pandemic and Risks Related Thereto*". See "*Risk Factors – Political Uncertainty*" and "*Risk Factors – Commodity Prices, Markets and Marketing*".

During the early summer months of 2023, wildfire activity impacted Canadian crude production throughout the second quarter. In addition, many facilities experienced lengthy maintenance updates, which resulted in lower overall production. Despite the setbacks, it is estimated that Canadian oil companies aim to add nearly 8% to Canada's total output over the next two years, signaling an increase in growth and demand for crude oil production in the country. The anticipated growth in exports and crude oil prices is supported by the progress of the Trans Mountain Pipeline which is expected to increase the pipeline's capacity by 590,000 barrels per day, to a total of 890,000 barrels per day.

## **Natural Gas**

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

While crude oil prices show a different trajectory, natural gas prices are expected to remain subdued for the next few months in light of the predicted warmer 2024 winter. Exceptionally high production levels in both Canada and the U.S., alongside storage reserves in Europe and North America, have collectively contributed to maintaining lower natural gas prices.

## **Natural Gas Liquids**

The pricing of condensates and other NGLs such as ethane, butane, propane and pentane plus sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. The profitability of NGL 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 NGL, 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**

In the summer of 2019, the Canadian Energy Regulator (the "**CER**") was created. The CER's governing legislation is the *Canadian Energy Regulator Act* ("**CERA**") and the *Impact Assessment Act* (the "**IAA**"). The CER is responsible for the export of crude oil, natural gas and NGL from Canada.

Exports of crude oil, natural gas and NGL from Canada are subject to the CERA and remain subject to the *National Energy Board Act Part VI (Oil and Gas) Regulation* (the "**Part VI Regulation**") until the Part VI Regulation is replaced. The CERA and the Part VI Regulation authorize crude oil, natural gas and NGL exports under: (i) short-term orders for up to one or two years depending on the substance, and up to 20

years for quantities of natural gas not exceeding 30,000 m<sup>3</sup> per day; or (ii) long-term export licences of up to 40 years for natural gas and up to 25 years for crude oil and other substances (e.g. NGL). With respect to applications for long-term export licences, following a review of such applications by the CER, which may involve a public hearing, the CER can approve an application if it is satisfied, among other considerations, that the proposed export volumes do not exceed Canada's reasonably foreseeable needs. In addition to CER approval, long-term export licences also currently require various other ministerial and federal Cabinet approvals.

Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the CER and the federal government.

## **Transportation Constraints and Market Access**

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

### ***Pipelines***

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

Under the Canadian Constitution, interprovincial and international pipelines fall within the federal government's jurisdiction. 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. Consequently, even when projects are approved, they often face delays due to actions taken by provincial and municipal governments, public interest groups and legal opposition. These issues often relate to Indigenous rights and title, the government's duty to consult and accommodate Indigenous peoples and the sufficiency of all relevant environmental review processes and assessments. Export pipelines from Canada to the United States face additional unpredictability, as such pipelines require approvals of several levels of government in the United States.

In the face of such regulatory uncertainty, the Canadian petroleum and natural gas industry has experienced significant difficulty expanding the existing network of transportation infrastructure for crude oil, natural gas and NGL, including pipelines, rail, trucks, and marine transport. Improved access to global markets through the midwest United States and export shipping terminals on the west coast of Canada could help to alleviate downward pressure on commodity prices. Several proposals have been announced to increase pipeline capacity from Western Canada to Eastern Canada, the United States, and other international markets via export terminals. While certain projects are proceeding, the regulatory approval process and other factors related to transportation and export infrastructure have led to the delay, suspension or cancellation of a number of pipeline projects.

## *Specific Pipeline Updates*

### Line 3 Replacement

With respect to the current state of the transportation and exportation of crude oil from Western Canada to domestic and international markets, Enbridge Inc.'s ("**Enbridge**") Line 3 Replacement Project (the "**Line 3 Replacement**") from Hardisty, Alberta, to Superior, Wisconsin, faced significant challenges in getting to operation. The U.S segment of the pipeline replacement was delayed due to permitting issues, particularly following the Minnesota Pollution Control Agency announcement requiring a public hearing concerning a key water permit. In June 2021, the Minnesota Court of Appeals affirmed the Minnesota Utilities Commission's decision to grant Enbridge a certificate of need and a pipeline routing permit for the final segment of the Line 3 Replacement. The Minnesota Supreme Court declined to hear an appeal on this matter. Nonetheless, after more than eight years, on September 29, 2021 Enbridge announced the completion of the 542 km Minnesota segment of the Line 3 Replacement. The Line 3 Replacement's in-service date was October 1, 2021 and transports 760,000 barrels per day at full capacity.

In October 2022, a Minnesota District Court upheld approvals given to the Line 3 Replacement, which were challenged on the basis that the U.S. Army Corps of Engineers should have taken into consideration how the broader project would impact climate change. The U.S. Army Corps of Engineers limited their environmental review of the project only to the impacts of construction in Minnesota rather than downstream concerns like GHG emissions from the ultimate burning of the crude oil carried in the pipeline.

### Line 5 Tunnel Replacement Project

In December 2023, Michigan Regulators approved Enbridge's Line 5 Tunnel Replacement Project ("**Line 5**"), marking the end of a more than three-year-long evaluation process. Line 5 is seen as crucial infrastructure supplying Michigan, Ontario and Québec. This approval, totaling US\$500 million, begins the process of replacing seven kilometres of the current pipeline with a new underwater tunnel in the Straights of Mackinac. The pipeline will be housed within a concrete tunnel beneath the lakebed. The tunnel project must first be approved by the U.S. Army Corps of Engineers at the United States federal level before construction can commence. The U.S. Army Corps of Engineers has initiated an environmental impact assessment, projecting completion by 2026.

### Trans Mountain Pipeline

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016 and has been subject to a number of challenges, including political opposition and challenges. The Trans Mountain Pipeline expansion project faced a series of construction-related challenges throughout the third and fourth quarters of 2023. In September 2023, Trans Mountain faced a potential nine-month delay over a reroute approval in the Jacko Lake area near Kamloops, British Columbia, due to difficulties identified during the tunnel drilling process. The reroute requested by Trans Mountain was necessary in order to avoid micro-tunneling construction that would likely be unfeasible. The request was opposed by the Stk'emlupsemc Te Secwepemc Nation ("**SSN**") First Nation, whose territory the pipeline crosses. The SSN argued that changing the route would disturb lands that hold "profound spiritual and cultural significance". After a three day hearing, the CER approved the route change request on a 1.3-kilometer section of the pipeline. Following the CER's release of the reasons for its decision, the SSN did not file an appeal or a variance request.

In November 2023, Trans Mountain faced another regulatory hearing on a pipeline variance request of a section of pipeline between Hope and Chilliwack, British Columbia. Trans Mountain applied for a variance request due to very challenging conditions, including the hardness of the rock that needed to be drilled. Trans Mountain requested permission to change the diameter, wall thickness, and coating for a 2,300-

meter stretch of the pipeline, differing from its initial approval. The CER ordered Trans Mountain to attend an oral hearing in November 2023 to provide further information or justification. In early December 2023, the CER denied the variance request, causing a potential two-year delay and additional losses. On January 12, 2023, the CER reversed its decision, approving the request for change, allowing construction to continue with completion to likely be completed early 2024.

Construction commenced on the Trans Mountain Pipeline expansion in late 2019 and mechanical completion of the project is now expected to occur in the second quarter of 2024.

### Keystone XL Pipeline

TC Energy Corporation's ("**TC Energy**") Keystone XL Pipeline was expected to begin construction in the first half of 2019, however, was subject to legal and regulatory barriers in the United States, particularly as it relates to the underlying environmental review that was undertaken and opposition from Native American tribes attempting to block certain permits. On January 20, 2021, Mr. Joseph Biden was sworn in as the 46<sup>th</sup> President of the United States, following which the Biden administration announced its decision to revoke the federal permit granted by the previous administration for the Keystone XL Pipeline, which overturned a comprehensive regulatory process that lasted more than a decade. As a result of the revocation, and following a comprehensive assessment of its options and consulting with its partners and stakeholders, including the Government of Alberta, on June 9, 2021, TC Energy terminated the Keystone XL Pipeline project.

The United States presidential election is set to occur in the fall 2024, which may result in a shift in the political agenda in the United States in the coming years, including a change in control of the house and/or the senate. Uncertainty remains as to the advancement of pipeline projects between Canada and the United States.

### *Marine Tankers*

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

### *Crude Oil and Bitumen by Rail*

In the spring of 2019, the Government of Alberta announced it would cancel the previously announced program to lease 4,400 rail cars capable of transporting 120,000 bbl/d of crude oil out of the province and assign the transportation contracts to industry proponents. In February 2020, the Government of Alberta announced it had sold \$10.6 billion worth of crude-by-rail contracts to the private sector.

Following two train derailments that led to fires and oil spills in Saskatchewan, the federal government announced in February 2020, that trains hauling more than 20 cars carrying dangerous goods, including crude oil and diluted bitumen, would be subject to reduced speed limits. The order was updated in early April 2020 and will remain in place until permanent rule changes are approved. As a result, trains subject to the order will be required to adhere to the reduced speed limits announced in February 2020 within metropolitan areas, with further mandatory speed reductions applying outside of metropolitan areas during winter months (November 15 to March 15). As of the date of this AIF, no permanent rules have been 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 (at times producers have received negative pricing for their natural gas production).

Required repairs or upgrades to existing pipeline systems in Western Canada have also led to further reduced capacity and apportionment of access, the effects of which have been exacerbated by storage limitations. However, in September 2019, the CER approved a policy change by TC Energy on its NOVA Gas Transmission Ltd. ("**NGTL**") pipeline network (the "**NGTL System**") to prioritize deliveries into storage ("**temporary service protocol**"). The change has served to somewhat stabilize supply and pricing, particularly during periods of maintenance on the system. An expansion to the NGTL System was recommended for approval by the CER, which was sent to the federal Cabinet for final approval. On April 30, 2021, the Governor in Council approved the issuance of the certificate of public convenience by the CER. Construction began on the NGTL System in 2021 with a majority of the project components reaching in-service for firm contracts for all project components in early 2023.

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

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

In August 2023, TC Energy sought regulatory approval for a potential minority interest sale of its NGTL System. The sale would result in a restructuring in order to facilitate potential future minority ownership of the system, including possible participation from Indigenous groups. As of the date of this AIF, no transaction has been announced. In early 2024, TC Energy has begun discussions with Indigenous groups regarding a potential sale.

It is anticipated that all project components will reach in-service in the first quarter of 2024.

Development of both provincial and federal frameworks may also impose restrictions on natural gas and LNG projects in Canada, particularly as provincial and federal governments work to achieve emissions reduction targets.

### *Specific Pipeline and Proposed LNG Export Terminal Updates*

#### Coastal GasLink Pipeline

While a number of LNG export plants have been proposed in Canada, regulatory and legal uncertainty, opposition from environmental and Indigenous groups and changing market conditions have resulted in the cancellation or delay of many of these projects. Nonetheless, in October 2018, the joint venture partners of the LNG Canada LNG export terminal announced a positive final investment decision. The Coastal GasLink pipeline (the "**CGL Pipeline**") was built by TC Energy, construction of which began in 2018. Despite its approval, the CGL Pipeline faced intense legal and social opposition.

In October 2023, it was announced that the 670 kilometre pipeline installation had been completed ahead of its year-end target. The project will allow LNG Canada to transport natural gas from northeastern British

Columbia to the LNG Canada liquefaction facility and export terminal in Kitimat, British Columbia via the CGL Pipeline. Once in service, 17 First Nations that are situated along the pipeline route have signed an agreement for the option to buy a 10% stake.

#### Woodfibre LNG Project

In December 2019, the CER approved a 40-year export licence for the Kitimat LNG project (the "**Woodfibre LNG Project**"). The Woodfibre LNG Project is a small-scale LNG processing and export facility near Squamish, British Columbia. The BC Oil and Gas Commission ("**BC Commission**") approved a project permit for the Woodfibre LNG Project in July 2019. In April 2022, a Notice to Proceed was issued, instructing the contractor to begin the work required to move the project toward major construction commencement in 2023. In July 2022, Pacific Energy Corporation Limited and Enbridge entered into a partnership agreement agreeing to jointly invest in the construction and operation of the Woodfibre LNG Project.

In November 2022, proposals were made to amend certain conditions listed in the project's Decision Statement, concerning technical feasibility. These proposed amendments were then issued for public comment. On November 9, 2023, the British Columbia Environmental Assessment Office ("**BC EAO**") approved the amendment to the environmental assessment certificate for the Woodfibre LNG Project to allow for a temporary floating worker accommodation, or 'Floatel', as well as its associated mooring, access infrastructure, and onshore drinking-water treatment facility. The 'Floatel' is expected to arrive in 2024. On July 31, 2023, the project officially commenced construction on the first of the proposed eighteen modules for the project. The Woodfibre LNG Project is expected to be substantially completed in the third quarter of 2027.

#### The Énergie Saguenay Project

GNL Québec Inc., the proponent of the Énergie Saguenay project (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 the Saguenay Fjord, an inlet which feeds into the St. Lawrence River in Québec. The Énergie Saguenay Project is currently slated for completion in 2026; however, on February 7, 2022 the Impact Assessment Agency of Canada (the "**IA Agency**") concluded the project was likely to cause adverse environmental impact. Although the federal government has rejected the initial plan, GNL Quebec Inc. is not prevented from submitting a new or revised project proposal for authorization. As of early January 2024, no revised proposal has been submitted.

#### Cedar LNG Project

Cedar LNG Export Development Ltd.'s Cedar LNG project (the "**Cedar LNG Project**") near Kitimat, British Columbia is set to be the first Indigenous majority owned LNG project in the world. On June 8, 2021 the Haisla First Nation and Pembina Pipeline Corporation ("**Pembina Pipeline**") announced a partnership agreement whereby Pembina Pipeline will become the Haisla Nation's partner in the development of the Cedar LNG Project. The BC EAO completed its assessment of the application for an environmental assessment certificate in November 2022 on behalf of the IA Agency. A report of the BC EAO's impact assessment was submitted to the Minister of Environment and Climate Change in November 2022. On March 15, 2023 both the provincial and federal government provided a decision statement indicating the project may proceed, and construction of the project must substantially begin within 5 years of the decision date.

On January 4, 2024, the selection for engineering, procurement and construction design, and fabrication and delivery of the floating LNG production units was completed. This selection marks a significant advancement for the Cedar LNG Project, now positioned in an advanced stage of planning and development, with the final investment decisions anticipated in the first quarter of 2024. Pending the expected announcement, construction for the project may commence in the second quarter of 2024, targeting the delivery of the floating LNG units by 2028.

## Ksi Lisims LNG Project

The Nisga'a Nation, Rockies LNG Limited Partnership and Western LNG are proposing to jointly build the Ksi Lisims LNG natural gas liquefaction and marine terminal project (the "**Ksi Lisims LNG Project**"). The Ksi Lisims LNG Project is a proposed LNG facility to be located on a site owned by the Nisga'a Nation in British Columbia. The Ksi Lisims LNG Project is currently undergoing its review by the BC EAO following its application for an environmental certificate in October 2023. A public comment period on the Ksi Lisims LNG Project was held from November 1 to December 1 of 2023. The BC EAO is conducting the environmental. The BC EAO will review feedback and provide direction to the proponents on how to revise their application. Subject to the foregoing, construction is anticipated to begin in 2024 with the site operational in late 2027 or 2028.

## **The United States Mexico Canada Agreement and Other Trade Agreements**

### **NAFTA/USMCA**

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

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

### **Other Trade Agreements**

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

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

In August 2023, an updated version of the Canadian Free Trade Agreement ("**CFTA**") was published, aiming to revamp the Agreement on International Trade to create a more robust and equitable trade environment within Canada.

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

## **Land Tenure**

### ***Mineral Rights***

The respective provincial governments (i.e. the Crown) predominantly own the mineral rights to most of the crude oil and natural gas located in Western Canada, with the exception of Manitoba (which only owns 20% of the mineral rights). Provincial governments grant rights to explore for, and produce, crude oil and natural gas pursuant to leases, licences and permits for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. The provincial governments in Western Canada's provinces conduct regular land sales where crude oil and natural gas companies bid for leases to explore for and produce crude oil and natural gas pursuant to mineral rights owned by the respective provincial governments. Crude oil and natural gas leases generally have a fixed term; however, a lease may generally be continued after the initial term where certain minimum thresholds of production have been reached, all lease rental payments have been paid on time, and other conditions are satisfied.

To develop crude oil and natural gas resources, it is necessary for the mineral rights owner to have access to the surface lands as well. Each province has developed its own process for obtaining surface access to conduct operations that operators must follow throughout the lifespan of a well, including notification requirements and providing compensation to affected persons for lost land use and surface damage.

Each of the provinces of Western Canada have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or licence. 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.

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

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

Until recently, crude oil and natural gas activities conducted on Indian reserve lands were governed by the *Indian Oil and Gas Act* (the "**IOGA**") and the *Indian Oil and Gas Regulations, 1995*. 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.

On September 26, 2023, the Supreme Court of British Columbia ruled in *Gitxaala v British Columbia* (Chief Gold Commissioner) that British Columbia must consult Indigenous groups before registering mineral claims on their traditional territories under the *Mineral Tenure Act*. The Supreme Court of British Columbia deferred its decision for 18 months, giving time for the Government of British Columbia to create a consultation-based claims system or for government amendments to the *Mineral Tenure Act*. It is possible that this decision will have impacts on the mineral regime in other provinces.

### **Surface Rights**

To develop crude oil and natural gas resources, it is necessary for the mineral rights owner to have access to the surface lands as well. 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, each province has developed its own process for obtaining surface access to conduct operations that operators must follow throughout the lifespan of a well, including notification requirements and providing compensation to affected persons for lost land use and surface damage.

### **Royalties and Incentives**

#### *General*

Each province has legislation and regulations that govern royalties, production rates and other matters. The royalty regime in a given province is in addition to applicable federal and provincial taxes and is a significant factor in the profitability of oil sands projects and crude oil, natural gas and NGL production. Royalties payable on production from lands where the Crown does not hold the mineral rights are determined by negotiation between the freehold mineral owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by provincial regulation and are generally calculated as a percentage of the value of production.

Occasionally the governments of Western Canada's provinces create incentive programs for exploration and development. Such programs often provide for volume-based incentive programs, royalty rate reductions, royalty holidays or royalty tax credits and may be introduced when commodity prices are low to encourage exploration and development activity. In addition, incentive programs may be introduced to encourage producers to prioritize certain kinds of development or undertake initiatives using new technologies that may enhance or improve recovery of crude oil, natural gas and NGL, or improve environmental performance.

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

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

The Corporation has the flexibility to negotiate and adapt its royalty arrangements with third parties to affect the profitability of the exploration, development and production of crude oil and natural gas related to its

Lessor Interests or GORR Interests in the appropriate circumstances, including consideration of the existing royalty regime established by each province (as described below) and any amendments to that regime.

### *Alberta*

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

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

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

Producers pay a flat royalty rate of 5% of gross revenue from each well that is subject to the Modernized Framework until the well reaches payout. Payout for a well is the point at which cumulative gross revenues from the well equals the Drilling and Completion Cost Allowance for the well set by the AER. After payout, producers pay an increased post-payout royalty on revenues at a royalty rate between 5% and 40% for crude oil and pentanes and 5% and 36% for methane, ethane, propane and butane, all determined by reference to the then current commodity prices of the various hydrocarbons. Similar to the Old Framework, the post-payout royalty rate under the Modernized Framework varies with commodity prices and operates on a sliding scale. Once production in a mature well drops below a threshold level where the rate of production is too low to sustain the full royalty burden, its royalty rate is adjusted downward towards a minimum rate of 5% as the mature well's production declines. As the Modernized Framework uses deemed drilling and completion costs in calculating the royalty and not the actual drilling and completion costs incurred by a producer, low-cost producers benefit if their well costs are lower than the Drilling and Completion Cost Allowance.

Crude oil and natural gas producers are responsible for calculating their royalty rate on an ongoing basis. The Crown's royalty share of production is payable monthly and producers must submit their records showing the royalty calculation.

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

Oil sands production is also subject to Alberta's royalty regime. The Modernized Framework does not impact or change the oil sands royalty framework. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1% and 9% depending on the market price of crude oil, determined using the average monthly price, expressed in Canadian dollars, for West Texas Intermediate crude oil at Cushing, Oklahoma. Rates are 1% when the market price of crude oil is less than or equal to \$55/bbl and increase for every dollar by which the market price of crude oil increases to a maximum of 9% when crude oil is priced at \$120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of

between 1% and 9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar by which the market price of crude oil increases above \$55/bbl to a maximum of 40% when crude oil is priced at \$120/bbl or higher.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage crude oil and natural gas development and new drilling. In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources, including as applied to coalbed methane wells, shale gas wells and horizontal crude oil and natural gas wells. In addition to royalties, producers of crude oil and natural gas from Crown lands in Alberta are also required to pay annual rental payments at a rate of \$3.50 per hectare.

Royalty rates for the production of privately-owned crude oil and natural gas are negotiated between the producer and the resource owner. Producers and working interest participants may also pay additional royalties to parties other than the freehold mineral owner where such royalties are negotiated through private transactions.

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

### *Saskatchewan*

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

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

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

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, with targeted programs in effect for certain vertical crude oil wells, exploratory gas wells, horizontal crude oil and natural gas wells, enhanced crude oil recovery wells and high water-cut crude oil wells. As of April 1, 2021, on associated gas produced from wells other than gas wells, including natural gas produced from oil wells, the Minister of Energy and Resources implemented a five-year Associated Gas Royalty Moratorium on the collection of Crown Royalty and Freehold Production Tax. The moratorium is in connection with the Government of Saskatchewan's Growth Plan and is aimed at meeting the Government of Saskatchewan's regulatory obligations to reduce methane-based GHG emissions by 40% to 45% between 2020 and 2025. The Associated Gas Royalty Moratorium is applicable to natural gas produced on or after April 1, 2021 and before April 1, 2026.

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

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

### *Manitoba*

In Manitoba, the Crown owns only approximately 20% of the crude oil and natural gas rights in the province, with the remainder being freehold lands. The royalty amount payable on crude oil produced from Crown lands depends on the classification of the crude oil produced. Royalty rates on crude oil are calculated on a sliding scale with a range of 0% to approximately 42.8% based on the monthly crude oil production from a spacing unit, or crude oil production allocated to a unit tract under a unit agreement or unit order. For horizontal wells, the royalty on crude oil produced from Crown lands is calculated based on the amount of crude oil production allocated to a spacing unit in accordance with the applicable regulations. As such, the royalty payable by producers will vary depending on the underlying characteristics of the producer's assets.

Royalties payable on natural gas production from Crown lands are equal to 12.5% of the volume of natural gas sold, calculated for each production month.

The Government of Manitoba maintains a Drilling Incentive Program (the "**MB Incentive Program**") with the intent of promoting investment in the sustainable development of petroleum resources. The MB Incentive Program provides the licensee of newly drilled wells, or qualifying wells where a major workover has been completed, with a "holiday oil volume" pursuant to which no royalties are payable until the holiday oil volume has been produced. The MB Incentive Program consists of benefits that are specific to certain vertical, exploration and deep wells, as well as wells undergoing major workovers, wells for solution gas and wells converted to injection wells. In December 2022, the MB Incentive Program was extended without alteration for the period commencing January 1, 2023 and ending on December 31, 2024 while the Natural Resources and Northern Development Mining, Oil and Gas Branch reviews the current program.

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 Manitoba are required to pay monthly freehold production taxes. The freehold production tax payable on crude oil is calculated on a sliding scale between 0% and approximately 40% based on the monthly production volume and the classification of crude oil as old oil, new oil, third-tier oil, and holiday oil. Producers of natural gas from freehold lands in Manitoba are required to pay a monthly freehold production tax equal to 1.2% of the volume sold, calculated for each production month.



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

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

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

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

## **Regulatory Authorities and Environmental Regulation**

### ***General***

The Canadian petroleum 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 petroleum 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, future changes to environmental legislation, including legislation related to air pollution and *GHG* emissions (typically measured in terms of their global warming potential and expressed in terms of carbon dioxide equivalents ("**CO<sub>2</sub>e**")), may impose further requirements on operators and other companies in the petroleum and natural gas industry.

### ***Federal***

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

### ***Impact Assessment Act***

On August 28, 2019, the IAA at the same time that the CERA replaced the National Energy Board Act ("**NEB**") Act and the CER replaced the NEB. As part of the regulatory transition, the IA Agency replaced the Canadian Environmental Assessment Agency.

The enactment of the CERA and the IAA introduced a number of important changes to the regulation of federally regulated major projects and their 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. Despite this structural change, the CER has assumed the jurisdiction previously held by the NEB over matters such as the environmental and economic regulation of pipelines, transmission infrastructure and offshore renewable energy projects, including offshore wind and tidal facilities. In its adjudicative role, the CERA tasks the CER with reviewing applications for the development, construction and operation of many of these projects, culminating in their eventual abandonment.

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

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

In response to the publication of the IAA, the Government of Alberta submitted a reference question to the Alberta Court of Appeal regarding its constitutionality. On May 10, 2022, the Alberta Court of Appeal released its opinion stating that the IAA went beyond the federal Parliament's constitutional authority and reached into areas of exclusive provincial authority. The federal government appealed the Alberta Court of Appeal's opinion to the Supreme Court of Canada ("**SCC**"). The SCC held the hearing in March 2023.

On October 13, 2023, the SCC ruled that the "designated projects" scheme set out in the IAA and its accompanying regulations were unconstitutional. However, the SCC reached a unanimous decision affirming the constitutional validity of the section within the IAA that pertains to projects conducted or funded by federal authorities on federal lands or abroad. The SCC found that "designated projects" scheme under the IAA was unconstitutional as it was seen as overreaching federal authority. This portion of the IAA was criticized for regulating entire projects, rather than focusing solely on areas falling under federal jurisdiction.

This decision has significant implications for the development of natural resources, energy and infrastructure projects in Canada. While the federal government works to bring the IAA into compliance with the guidance as set out by the SCC, the *Impact Assessment Act* ("**Interim Guidance**") was enacted, and will remain in place until the IAA is revised. During this interim period, the federal government will not be using its discretionary process to designate projects under the IAA until the legislation has been revised. The Federal Minister of Environment announced it will work with the provinces and Indigenous groups to ensure the impact assessment process works for all. The revisions to the IAA will require that only those projects that can result in adverse federal effects are targeted. Until such time as the revised IAA has been released, proponents must comply with the Interim Guidance and it is unknown the potential effects that the Interim Guidance or the revised IAA may have on the oil and gas industry.

### *Clean Fuel Regulations*

On July 1, 2023, the obligations under the *Clean Fuel Regulations* ("**CFR**") came into effect. The objective of the *Clean Fuel Standard* ("**CFS**") is to achieve 30 million tonnes of annual reductions in GHG emissions by 2030. The CFR requires liquid fossil fuel primary suppliers (i.e. producers and importers) to reduce the carbon intensity ("**CI**") of the liquid fossil fuels they produce in, and import into, Canada. The CFR has also established a credit market, whereby the annual CI reduction requirement can be met via three main categories of credit-creating actions: (i) actions that reduce the CI of the fossil fuel throughout its lifecycle; (ii) supplying low-carbon fuels; and (iii) specified end-use fuel switching in transportation.

### *Regulations Amending the Output-Based Pricing System Regulations and the Environmental Violations Administrative Monetary Penalties Regulation*

On November 22, 2023, the federal government published amendments to the Output-based Pricing System ("**OBPS**"). These regulations are made under the *Greenhouse Gas Pollution Pricing Act* ("**GGPPA**"). These changes involve adding and revising output-based standards ("**Standards**"), enhancing implementation procedures, refining reporting accuracy, and encouraging voluntary participation. Notably, the updated OBPS introduces a 2% fixed annual tightening rate for most Standards starting from 2023. Sectors facing significant competition and carbon pricing-induced carbon leakage will experience a 1% adjusted tightening rate from 2023 onwards. Additionally, the publication of the *Quantification Methods for the Output-Based Pricing System Regulations* ("**OBPS QM**"), detailing emissions quantification methods, was released on December 12, 2023. The OBPS QM establishes the required methods for quantifying greenhouse gases, heat ratios, and electricity generated within the OBPS framework.

### *Regulatory Framework for an Oil and Gas Sector Greenhouse Gas Emissions Cap*

On December 7, 2023, the federal government published the *Regulatory Framework for an Oil and Gas Sector Greenhouse Gas Emissions Cap* ("**GHG Cap**"). Under the GHG Cap, LNG projects would be captured by cap-and-trade system. The provincial and federal governments aim to work together to ensure the regulations and programs complement each other to minimize additional administrative requirements. The key elements of the GHG Cap include: (i) decline of emissions to meet net-zero by 2050; (ii) creating the legal upper bound on emissions (being the maximum emissions the whole sector may be allowed to emit per year) in a manner responsive to technically achievable emissions reductions and the global demand for oil and gas; (iii) minimal administrative burden; and (iv) ongoing monitoring and regular review of the standards. Draft regulations are planned to be released by mid-2024.

In 2024, the federal government plans to publish proposed regulations for a 60-day public comment period. Formal written comments will also be sought on the proposal at that time. The final regulations are expected to be published by 2025. The initial reporting responsibilities could come into effect as early as 2026, while the complete system requirements are set to be gradually implemented between 2026 and 2030.

### *United Nations Declaration on the Rights of Indigenous Peoples Act*

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

## **Alberta**

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

The Government of Alberta relies on regional planning to accomplish its resource development goals. Its approach to natural resource management provides for engagement and consultation with stakeholders and the public and examines the cumulative impacts of development on the environment and communities. While the AER is the primary regulator for energy development, several other governmental departments and agencies may be involved in land use issues, including the Alberta Ministry of Environment and Protected Areas (previously known as the 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.

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

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

## **Saskatchewan**

The Saskatchewan Ministry of Energy and Resources is the primary regulator of crude oil and natural gas activities in the province. *The Oil and Gas Conservation Act* (the "**SKOGCA**") is the act 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.

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

Saskatchewan launched the Inactive Liability Reduction Program ("**ILRP**") in January of 2023. The ILRP aims to reduce the total number of inactive liabilities for oil and gas companies. The program currently requires oil and gas companies to retire 5% of their inactive liabilities such as inactive wells, and facilities in Saskatchewan. It is anticipated that this percentage will gradually increase over time, with the 2024 estimate being 6%.

### **Manitoba**

In Manitoba, the Petroleum Branch of the Department of Growth, Enterprise and Trade develops, recommends, implements and administers policies and legislation aimed at the sustainable, orderly, safe and efficient development of crude oil and natural gas resources. Crude oil and natural gas exploration, development, production and transportation are subject to regulation under *The Oil and Gas Act* (the "**MBOGA**"), *The Oil and Gas Production Tax Act* and related regulations and guidelines. The *Environment Act* establishes the environmental assessment and licensing process for developments in Manitoba for projects which may have the potential to cause significant environmental and / or human health effects. Projects which are defined as developments which must undergo the environmental assessment and licensing process are listed in the *Classes of Development Regulation*.

### **Liability Management Rating Programs**

#### **Alberta**

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

The announcement and implementation of the AB LMF and the desire to rethink liability management in Alberta follows the SCC's decision in *Orphan Well Association v Grant Thornton Ltd.* (also known as the "**Redwater decision**"). As a result of the Redwater decision, receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licencees or to require a licencee to pay a security deposit before approving a transfer when such a licencee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets that have reached the end of their productive lives (and therefore represent a net liability) in order to deal primarily with the remaining productive and valuable assets without first satisfying any abandonment and reclamation obligations associated with the insolvent estate's assets. In April 2020, the Government of Alberta passed Bill 12: *The Liabilities Management Statutes Amendment Act* (the "**LMSAA**") which came into force on proclamation. The LMSAA places the burden of a defunct licencees' abandonment and reclamation obligations first on the defunct licencee's working interest partners, and second, the AER may order the orphan fund (the

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

Alberta's OGCA established an Orphan Fund which is run by the Orphan Well Association ("**OWA**") to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline if a 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 former Licensee Liability Rating Program (the "**AB LLR Program**") and Alberta Oilfield Waste Liability Program (the "**AB OWL Program**") who contributed to a levy administered by the AER. However, the Government of Alberta has loaned the Orphan Fund approximately \$335 million. The Government also covered \$113 million in levy payments that 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. Collectively, these programs were 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. Under the new AB LMF, the OWA has broader authority to assist in the reclamation and remediation of wells, facilities or pipelines.

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

Following the Redwater decision, Alberta has committed to actively reducing inventories of orphan and inactive well sites in the province. The primary goals of the AB LMF are to assist in addressing the OWAs inventory and, creating a framework and regulatory scheme that will better manage site reclamation throughout the lifecycle of a project. The AB LMF addresses five key components supporting a lifecycle approach to liability management: (i) practical guidance and support for distressed operators; (ii) a licensee capability assessment system to provide proactive support through ongoing financial capability review; (iii) mandatory spend targets to support inventory reduction; (iv) a process to address legacy and post-closure sites or sites that were remediated, reclaimed or abandoned prior to the AB LMF; and (v) the OWA taking on a more involved role in managing clean-up of oil and natural gas facilities and infrastructure.

On December 1, 2021, the Government of Alberta announced amendments to Directive 006: *Licensee Liability Rating (LLR) Program* and a new Directive 080: *Licensee Life-Cycle Management* and accompanying Manual 023: *Licensee Life-Cycle Management*. A new Directive 067: *Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals* was also introduced in April 2021 which introduced new criteria for the AER to consider whether an applicant, licensee or approval holder poses an "unreasonable risk" of orphaning assets. Among other changes under the AB LMF, the AB LLR Program and security deposit collection for licence transfer have been replaced with the Licensee Capability Assessment System, which is intended to be a more comprehensive assessment of corporate health and will consider a wider variety of factors than those considered under the AB LLR Program and will establish clear expectations for industry with regards to the management of liabilities throughout the entire lifecycle of crude oil and natural gas projects. Importantly, the AB LMF provides proactive support to distressed operators and requires companies operating in Alberta's petroleum and natural gas industry to make mandatory annual minimum payments towards outstanding reclamation obligations in accordance with five-year rolling spending targets. Under the AB LMF, each licensee is required to meet mandatory annual spend targets for well closures and abandonments. During the summer of 2022, the AER announced it would increase spend targets for liabilities in 2023 from \$422 million to \$700 million and released forecasted targets through 2027, each of which are expected to increase annually by 9%.

As part of its strategy to encourage the decommissioning, remediation and reclamation of inactive or marginal crude oil and natural gas infrastructure, the AER announced a voluntary area-based closure ("**ABC**") program in 2018. The ABC program is designed to reduce the cost of abandonment and reclamation operations through industry collaboration and economies of scale. Participants seeking to

participate in the program must commit to an inactive liability reduction target to be met through closure work of inactive assets. The ABC, together with the inventory reduction program implemented under the AB LMF, which implements mandatory closure spend targets over a five-year rolling period, will enable companies to work together to share the costs of cleaning up multiple sites in one area.

On November 16, 2023, the AER provided an update on the ongoing implementation of the AB LMF. The process to implement the AB LMF involves updating various regulatory instruments and establishing a new security framework under the OGCA. The changes aim to improve risk assessment, ensure fair responsibility for cleanup in active sites, and streamline regulations. The new security framework will consider factors beyond the LLR, such as the entire energy development life cycle and the polluter-pays principle. Stakeholder engagement is planned for 2024 before releasing draft documents for public comment.

The AB LMF continues to be implemented by the AER with gradual and phasing changes to legislative, regulatory and AER directives required to effectively implement the AB LMF and properly phase-out the AB LMR Program as the AB LMR Program is integrated in several directives and throughout governing legislation.

### **Saskatchewan**

The Saskatchewan Ministry of Energy and Resources administers the Licensee Liability Rating Program (the "**SK LLR Program**"), which was updated in January 2023. The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to the orphan fund (the "**Oil and Gas Orphan Fund**") established under the SKOGCA. The Oil and Gas Orphan Fund takes on the obligation of carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when the Saskatchewan Ministry of Energy and Resources confirms there is no legally responsible or financially able party to deal with the abandonment and/or reclamation responsibilities. The SK LLR Program requires all new licensees to submit a \$10,000 non-refundable Orphan Fund fee in order to be deemed eligible to transfer licences, and all licensees whose deemed liabilities exceed their deemed assets (i.e., an LLR below 1.0) are required to post a security deposit. The ratio of deemed assets to deemed liabilities is assessed once each month for all licensees of crude oil, natural gas and service wells and upstream crude oil and natural gas facilities and this data is publicly available.

In February 2021, the Energy Regulation Division of the Ministry of Energy and Resources announced that it was consulting with stakeholders on proposed regulatory enhancements intended to strengthen Saskatchewan's oil and gas liability management framework and reduce the prospect of new orphan oil and gas wells and facilities in Saskatchewan. This process led to the development of the new *Financial Security and Site Closure Regulations* (the "**Closure Regulations**"), which came into force on January 1, 2023.

The Closure Regulations include: (i) changes to the formula for determining if a licensee poses a risk; (ii) annual spend targets for closure activities by licensees; and (iii) new guidance on when a security deposit may be required by a licensee or in connection with a transfer. The OGCR remain in effect. Among other things, the OGCR provide a formula for determining a licensee's licensee liability rating, outline eligibility requirements for holding licences, and provide guidance on when a security deposit may be required by a licensee or in connection with a transfer.

### **Manitoba**

To date, the Government of Manitoba has not implemented a liability management rating program similar to those found in the other Western Canadian provinces. However, operators of wells licensed in the

province are required to post a performance deposit to ensure that the operation and abandonment of wells and the rehabilitation of sites occurs in accordance with the MBOGA and the *Drilling and Production Regulations*. The MBOGA also establishes the Abandonment Fund Reserve Account (the "**Abandonment Fund**"). The Abandonment Fund is a source of funds that may be used to operate or abandon a well or facility when the licensee or permittee fails to comply with the MBOGA. The Abandonment Fund may also be used to rehabilitate the site of an abandoned well or facility or to address any adverse effect on property caused by a well or facility.

Deposits into the Abandonment Fund are comprised of non-refundable levies charged when certain licences and permits are issued or transferred, as well as annual levies for inactive wells and batteries.

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

As part of an announcement of federal relief for Canada's petroleum and natural gas industry in response to COVID-19, the federal government pledged \$1.72 billion to clean up orphan and inactive wells in Alberta, Saskatchewan and British Columbia. However, these funds were administered by regulatory authorities in each province. In Alberta, the Ministry of Energy disbursed its \$1 billion share of the federally provided funds through the Site Rehabilitation Program, which is closed to new applicants. In addition to the funds administered by the respective provincial governments, the federal government announced a \$200 million loan to Alberta's Orphan Fund. And in early March 2020, the Government of Alberta announced an extension by up to \$100 million of an existing \$235 million loan to the Orphan Fund. In Saskatchewan, \$400 million in federal funding was used for the Accelerated Site Closure Program ("**ASCP**"). The first phase of the ASCP made \$100 million available to eligible service companies to conduct abandonment and reclamation work. In July 2022, the ASCP opened application processes to release all remaining ASCP funding to eligible licensees. The ASCP ended in the spring of 2023.

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

#### ***Federal***

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") since 1992. Since its inception, the UNFCCC has instigated numerous policy changes with respect to climate governance. As a result of the Paris Agreement, within the UNFCCC, the Canadian government put forth commitments to reduce GHG emissions. At the 27th United Nations Climate Change Conference of the Parties held in 2021, Prime Minister Trudeau made several pledges aimed at reducing Canada's GHG emissions and environmental impact, including a commitment to cap Canada's oil and gas emissions at the pace and scale needed to achieve net zero emissions by 2050. Canada recently participated in the 28<sup>th</sup> United Nations Climate Change Conference of the Parties to support successful and ambitious outcomes in line with the Paris Agreement in November 2023, at which, Minister Guilbeault reconfirmed Canada's commitments. The U.S. government has also recently renewed its commitment to the Paris Agreement. The Glasgow Climate Pact reaffirms the long-term global goals (including those in the Paris Agreement) to hold the increase in the global average temperature to below 2°C above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5°C above pre-industrial levels.



The Government of Canada has pledged to cut its emissions by 30% from 2005 levels by 2030, however, they have also indicated that they expect to implement policies to exceed this target. In connection with this target, the Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change in 2016, setting out a plan to meet the federal government's 2030 emissions reduction targets. In March 2022, the Government of Canada also introduced Canada's 2030 Emissions Reduction Plan (the "**2030 Reduction Plan**"), which provides the building blocks for the Canadian economy to achieve 40% to 45% emissions reductions below 2005 levels by 2030. The 2030 Reduction Plan includes \$9.1 billion in new investments as well as carbon pricing and clean fuels measures to assist in growing economic opportunities for a clean future. Progress of the 2030 Reduction Plan will be reviewed and produced in reports in 2023, 2025 and 2027, with additional targets to be developed for 2035 and 2050.

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

#### *Single-use Plastics Prohibition Regulations*

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

On November 16, 2023, the Federal Court ruled that the categorization of all "Plastic Manufactured Items" ("**PMIs**") as Toxic Substances in Schedule 1 of the *Canadian Environmental Protection Act, 1999* ("**CEPA**") was both unreasonable and unconstitutional. The Federal Court determined that the Government of Canada lacked sufficient evidence to label all PMIs as toxic, emphasizing that the authority to regulate substances for environmental protection only applies to those listed as toxic under CEPA. The federal government has indicated it plans to appeal this decision. Despite the SUPPR remaining in effect, the direct challenge brought by Petro Plastics Corp., RPUC and Oregon Precision Industries has been temporarily halted pending the resolution of the decision regarding the PMI designation under CEPA. With the recent issuance of the decision by the Federal Court, the challenge against the SUPPR will likely continue in 2024.

#### *Canadian Net-Zero Emissions Accountability Act*

On November 19, 2020, the federal government announced Bill C-12, an Act respecting transparency and accountability in Canada's efforts to achieve net-zero GHG emissions by the year 2050. Canada joined over 120 countries in committing to net-zero emissions by 2050, including the UK, Germany, France and Japan. The *Canadian Net-Zero Emissions Accountability Act* became law in June 2021 and legally binds the federal government to a process to achieve net-zero emissions by 2050. The legislation also sets rolling five-year emissions-reduction targets (starting in 2030) and requires emissions reduction plans to reach each target on a reporting basis and enshrines greater accountability and public transparency into Canada's

plan for meeting net-zero emissions by 2050 by providing for independent third-party review by the Commissioner of the Environment and Sustainable Development.

### *Greenhouse Gas Pollution Pricing Act*

On June 21, 2018, the federal government enacted the GGPPA, which came into force on January 1, 2019. This regime has two parts: the OBPS and a regulatory fuel charge (the "**Fuel Charge**") imposing an initial price of \$20/tonne of CO<sub>2</sub>e. This system applies in provinces and territories that request it and in those that do not have their own emissions pricing systems in place that meet the federal standards. The effect of the GGPPA is that, regardless of whether a particular province has enacted legislation of its own, there is a uniform price on emissions across the country. In accordance with the HEHE Plan, the price on carbon is set to increase annually at a rate of \$15/tonne of CO<sub>2</sub>e per year commencing in 2023 through to 2030. In August 2021, the federal government established strengthened minimum national standards (the "**federal benchmark**") for 2023 to 2030, which includes the requirement that all jurisdictions establish systems that align with the federal carbon pricing trajectory and benchmark requirements to 2030. Once in place, the systems will remain until 2027.

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

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

Following the SCC's decision upholding the constitutionality of the GGPPA, any province or territory has the flexibility to design their own pricing system, so long as it meets the minimum national stringency standards or federal benchmarks. Currently the provincial systems, together with the Fuel Charge apply in each of Alberta, Saskatchewan, Ontario, New Brunswick, Nova Scotia and Newfoundland and Labrador. The provincial plans in each of British Columbia, Québec and the Northwest Territories apply in full in those jurisdictions while the OBPS and Fuel Charge apply in each of the Yukon, Nunavut, Manitoba and Prince Edward Island. For so long as the provincial systems in Alberta (under the *Technology Innovation and Emissions Reduction ("TIER")* regulation), British Columbia and Saskatchewan meet the federal stringency standards for the emissions they cover, these systems will continue to apply, with the backstop covering those emissions not covered by the provincial systems, as applicable.

### *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds*

On October 29, 2020, the federal government launched the \$750-million Emission Reduction Fund to reduce methane and GHG emissions. The fund will provide repayable funding to eligible onshore and offshore crude oil and natural gas companies to support investments to reduce GHG emissions by adopting greener technologies. Part of this fund is directed towards methane reduction.

On April 26, 2018, the federal government passed the *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* (the "**Federal Methane Regulations**"). The Federal Methane Regulations seek to reduce emissions of methane from the petroleum and natural gas industry, and came into force on January 1, 2020. By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and the

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

On December 4, 2023, the Minister of Environment and Climate Change announced amendments to the Federal Methane Regulations that seek to further cut emissions. These amendments closely mirror those in the United States and echo the International Energy Agency's call to curtail methane emissions from the oil and gas sector by 75% by 2030. These amendments signify a significant reinforcement to Canada's methane strategy. The draft amendments are undergoing consultation until mid-February 2024. Alberta has opposed the amendments, stating it will take measures to ensure the amended regulations are not implemented in Alberta. It is unknown at this time what the potential effects of the amended Federal Methane Regulations may be.

### *Clean Fuel Regulations*

Coming into force on June 20, 2022 with obligations under the CFS taking effect July 1, 2023, the CFR take a performance-based approach to reducing greenhouse gas emissions. The CFR require suppliers of liquid fuels, such as gasoline, diesel and kerosene to reduce the carbon intensity of their liquid fossil fuels. Beginning in 2023, the carbon intensity reduction requirement started at 3.5 g CO<sub>2</sub>e/MJ, increasing by 1.5 gCO<sub>2</sub>e/MJ each year and reaching 14 gCO<sub>2</sub>e/MJ in 2030. The CFS applies to any company that domestically produces or imports at least 400 cubic metres of liquid fossil fuels for use in Canada. It is the goal of the program to incentivize innovation and adoption of clean technologies while giving fuel suppliers the ability to meet requirements in a cost-effective way that works for their business. The CFR offer compliance credits, tracked via the Credit and Tracking System, and create a credit market to incentivize industries to innovate and adopt cleaner technologies to lower their compliance costs.

### *Clean Electricity Regulation*

On August 10, 2023, the federal government released a draft of the *Clean Electricity Regulations* which will help drive progress towards a net-zero electricity grid by 2035. The *Clean Electricity Regulations* are part of a suite of measures by the Government of Canada from the 2030 Emissions Reduction Plan to transition to clean energy. Developed under CEPA, these regulations establish stringent pollution emission standards without prescribing specific technologies. This technology-neutral stance aims to grant flexibility to provincial, territorial, and municipal authorities as they transition to clean energy.

The Alberta Government has contested the constitutionality of the draft *Clean Electricity Regulations* and urged the federal government to support Alberta's plan for achieving carbon neutrality by 2050. On November 27, 2023, Alberta issued notice of its intention to invoke a resolution under the *Alberta Sovereignty within a United Canada Act* (the "**Sovereignty Act**") in response to the draft *Clean Electricity Regulations*. This resolution directs specific provincial entities from enforcing or complying with the *Clean Electricity Regulations* "to the extent legally permissible." Similarly, the Government of Saskatchewan plans to utilize *The Saskatchewan First Act* to establish a tribunal to assess the economic impacts of the *Clean Electricity Regulations*. Consequently, there is a strong possibility that once implemented, the *Clean Electricity Regulations* will face constitutional challenges.

### *Air Pollutant Regulations*

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

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

#### *Framework to Phase Out Fossil Fuels*

On July 24, 2023, the Minister of Environment and Climate change released the *Inefficient Fossil Fuel Subsidies Government of Canada Self-Review Assessment Framework* and the *Inefficient Fossil Fuel Subsidies Government of Canada Guidelines*. The documents will support the federal government's focus on clean energy and net-zero initiatives and the de-carbonization of Canada's oil and gas sector. Pursuant to the Framework, subsidies are deemed "inefficient" unless they satisfy certain criteria, which include, but are not limited to: supporting clean energy, clean technology, or renewable energy; providing essential energy service to a remote community; providing short-term support for emergency response; supporting Indigenous economic participation in fossil fuel activities; or supporting abated production processes, such as carbon capture, utilization, and storage, or projects that have a credible plan to achieve net-zero emissions by 2030.

#### *Bill S-5- Recognizing the Right to a Healthy Environment*

On June 13, 2023, Bill S-5 *Strengthening Environmental Protection for a Healthier Canada Act* to amend CEPA, received royal assent. The amendments include changes to the preamble of CEPA, which now recognizes that every individual in Canada has a right to a healthy environment. Section 2 of CEPA now requires that the federal government protect this right, and that an implementation framework be developed to consider how this right will be administered under CEPA, which is anticipated to be published by 2025. Further amendments include creating a risk assessment Plan of Chemical Management Priorities, setting out a multi-year assessment of substances and activities, and a commitment to consider the cumulative effects of these assessments on vulnerable populations

#### **Alberta**

In June 2019, in accordance with the GGPPA, the Fuel Charge took effect in Alberta. Currently the carbon tax payable in Alberta is \$65/tonne of CO<sub>2e</sub> and will increase to \$80/tonne on April 1, 2024. In December 2019, the federal government approved Alberta's TIER regulation, which applies to large emitters and those who have opted-in. The TIER regulation came into effect on January 1, 2020 and replaced the previous *Carbon Competitiveness Incentives Regulation*.

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

The TIER regulation applies to emitters that emit more than 100,000 tonnes of CO<sub>2e</sub> per year in 2016 or any subsequent year. The 2020 target for most TIER-regulated facilities is to reduce emissions intensity by 10% as measured against that facility's individual benchmark, with a further 1% reduction for each subsequent year. The facility-specific benchmark does not apply to all facilities. Under the amendments, a 2% annual tightening rate will apply to facility-specific and high performance benchmarks. Certain facilities,

such as those in the electricity sector, are compared against the good-as-best-gas standard. Similarly, for facilities that have already made substantial headway in reducing their emissions, a different "high-performance" benchmark is available to ensure that the cost of ongoing compliance takes this into account. Under the TIER regulation, facilities in high-emitting sectors can opt-in to the program in specified circumstances despite the fact that they do not meet the 100,000 tonne threshold. The amendments reduced the threshold for those to opt-in from 10,000 tonnes of CO<sub>2</sub>e to 2,000 tonnes of CO<sub>2</sub>e per year. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports and facilities that are unable to achieve their targets may either purchase credits from other facilities, purchase carbon offsets, or pay a levy to the Government of Alberta. As discussed above, the TIER regulation will continue to apply in Alberta for as long as it meets the federal stringency standards and the federal backstop will apply to the emission sources not covered by the TIER program.

In furtherance of global emissions reductions targets, the Government of Alberta had announced a goal to lower annual methane emissions by 45% by 2025. Pursuant to this goal, the Government of Alberta enacted the *Methane Emission Reduction Regulation* (the *Alberta Methane Regulations*) on January 1, 2020 and the AER simultaneously released an updated edition of *Directive 060: Upstream Petroleum Industry Flaring, Incinerating and Venting* ("**Directive 060**"). The release of the updated Directive 060 complements a previously released update to *Directive 017: Measurement Requirements for Oil and Gas Operations* ("**Directive 017**") that took effect in December 2018. In November 2023, it was announced that Alberta had achieved its goal of reducing methane emissions by 45% by 2025, years ahead of schedule.

In May 2020, the Government of Canada and the Government of Alberta announced a preliminary equivalency agreement ("**Equivalency Agreement**") regarding the reduction of methane emissions. Through the Equivalency Agreement and Directive 060 and Directive 017, Alberta maintains jurisdiction over the regulation of the upstream oil and gas industry. Should amendments to the Federal Methane Regulation come into effect and Alberta challenges such amendments, it is unknown the potential effects of such legislation in Alberta, or the effects of any potential challenge to their implementation by the Government of Alberta.

Alberta was also the first jurisdiction in North America to direct dedicated funding to implement CCUS technology across industrial sectors. Alberta has committed \$1.24 billion through 2025 to fund two commercial-scale CCUS projects. Both projects will help reduce the CO<sub>2</sub> emissions from the oil sands and fertilizer sectors, and reduce GHG emissions by 2.76 million megatonnes per year.

On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*. It deemed the pore space underlying all land in Alberta to be and to have always been the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions. In May 2021, the Government of Alberta announced a competitive bid process under which it would issue rights for carbon sequestration, focusing on the development of strategically placed carbon sequestration hubs, avoiding stand-alone injection operations. As of the fall of 2022, the Government of Alberta approved a total of 25 hub proposals through two competitive bid processes. The selected companies have begun exploring how to safely develop their carbon storage hubs. If a proponent can successfully demonstrate their project can provide permanent storage, companies will have the opportunity to apply for the right to inject captured carbon dioxide at such project. The Government of Alberta has also announced it will invest \$40 million in 11 CCUS hub projects through Emissions Reduction Alberta.

On November 5, 2021, the Government of Alberta released the Alberta Hydrogen Roadmap. Hydrogen is positioned to play a significant role in the de-carbonization of the global economy and Alberta has significant opportunity to play a major role both nationally and internationally. The Hydrogen Roadmap is divided into two phases. The first phase focuses on establishing policy, investing in technology to reduce the carbon intensity of hydrogen production and accelerating commercialization across the supply chain. The second phase will focus on growth and achieving scale through improved technologies and commercialization. The

AUC also released its Hydrogen Inquiry Report in September 2022 which reviewed the viability and impacts of hydrogen blending into natural gas distribution systems in Alberta.

In February 2023 the TIER regulation was amended to, among other things, amend the opt-in thresholds for emissions-intensive and trade-exposed industries, tighten facility-specific benchmarks, revise the credit use limits and expiration periods as well as create sequestration credits for carbon capture, utilization and storage projects. The TIER regulation will be subject to a subsequent review which must be completed by December 31, 2026.

On August 3, 2023, the Alberta Ministry of Affordability and Utilities announced that the AUC was directed to pause approvals of new renewable electricity generation projects until February 29, 2024. The announcement was in response to the need to review and consider policy changes in relation to renewable development. The review of the policies for renewable resource development will include a public inquiry, after which the AUC must submit a report on the findings no later than March 29, 2024 to the Minister of Affordability and Utilities. It is unknown at this time what effect the renewable pause and corresponding inquiry may have on the energy market in Alberta.

### **Saskatchewan**

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

The MRGGA, which is partially compliant with the federal emissions trading system and was partially proclaimed into force on January 1, 2018, establishes a framework to reduce GHG emissions by 20% of 2006 levels by 2020. An amended version of the MRGGA was proclaimed in full on December 18, 2018, establishing the framework of an output-based emissions management framework. In November 2022, the province of Saskatchewan received confirmation that a provincial plan has been approved to replace the federally imposed carbon tax on industrial emitters effective as of January 1, 2023. The Saskatchewan OBPS meets the federal stringency requirements and regulated emitters will receive credit for every tonne of CO<sub>2e</sub> under their permitted amount. The OBPS program in Saskatchewan includes credits for emitters utilizing CCUS technologies at their facilities. As noted above, the Fuel Charge applies in Saskatchewan.

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

On April 10, 2019, Saskatchewan produced its first annual report on climate resilience. The report measures the province's progress on goals set out under *Prairie Resilience: A Made-in-Saskatchewan Climate*

*Change Strategy*. Among these goals is the aim of increasing the role of renewable energy in the provincial energy mix to 50% by 2030.

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

To facilitate its emissions reduction efforts, the Government of Saskatchewan has implemented *Directive PNG017: Measurement Requirements for Oil and Gas Operations*, which came into force in December 2019 and was amended in April 2020, and *Directive PNG036: Venting and Flaring Requirements*, which came into force in April 2020. Together with the Saskatchewan O&G Emissions Regulations, these directives enable the Government of Saskatchewan to regulate emissions reductions within the province. In November 2020, the Government of Canada and the Government of Saskatchewan announced that they had finalized an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply. The equivalency agreement terminates on or by December 31, 2024.

### **Manitoba**

In 2018, the Government of Manitoba unveiled the *Climate and Green Plan Implementation Act* (the "**Implementation Act**"). The Implementation Act included a new *Climate and Green Plan Act*, a new *Industrial Greenhouse-Gas Emissions Control and Reporting Act* and various related amendments to existing legislation. Initially, the *Climate and Green Plan Act* introduced a charge of \$25/tonne of CO<sub>2</sub>e on GHG emissions, but this was subsequently withdrawn from the legislation and the federal GGPPA applied in Manitoba. However, in March 2020, the Government of Manitoba introduced the *Climate and Green Plan Implementation Act, 2020*, which, among other things, reintroduces the \$25 charge.

Following Manitoba's challenge in the Federal Court, it was determined that the federal government's fuel charge will backstop Manitoba's system because Manitoba's pricing regime is not stringent enough. The \$25/tonne imposed by the *Climate and Green Plan Implementation Act, 2020* does not match increases in the federal benchmark and therefore is not a comparable system.

The original *Climate and Green Plan Implementation Act* also required the Government of Manitoba to establish five-year emissions reduction targets. In June 2019, the Government of Manitoba announced a GHG emissions reduction target of one megatonne for the 2018-2022 period. The Manitoba Government set the reduction target for the second five year period (2023 to 2027) at 5.6 megatonnes of CO<sub>2</sub>e emulative emissions reductions.

### **Accountability and Transparency**

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

### **Indigenous Rights**

Opposition by Indigenous people to the Corporation, our operations, development or exploration, or disagreements between Indigenous communities, or between Indigenous peoples and governments, in the

jurisdictions in which we conduct business may adversely impact our reputation, relationship with host governments, local communities and other Indigenous communities. Other impacts may include diversion of management's time and resources, increased legal, regulatory and other advisory expenses, and our ability to explore, develop and continue to operate projects.

In Canada, Indigenous and/or treaty rights held by Indigenous peoples are protected under the constitution. Impacts to these Indigenous and treaty rights must be considered, in particular in areas where the Corporation operates on Crown lands. In some cases, there may be outstanding Indigenous and treaty rights claims, which may include land title claims, on lands where we operate, and such claims, if successful, could have a material adverse impact on our operations or pace of growth.

The Canadian federal and provincial governments have a duty to consult with Indigenous people when contemplating actions that may adversely affect the asserted or proven Indigenous rights or affect treaty rights and, in certain circumstances, accommodate their interests. The scope of the duty to consult by federal and provincial governments varies with the circumstances and is often the subject of ongoing litigation the result of which may affect the way governments are required to fulfil their duty to consult. The fulfillment of the duty to consult Indigenous people and any associated accommodations may adversely affect our ability to, or increase the timeline to, obtain or renew permits, leases, licenses and other approvals, or to meet the terms and conditions of those approvals.

In addition, the Canadian federal government and the British Columbia provincial government have passed legislation which requires such governments to take all necessary measures to implement the United Nations Declaration on the Rights of Indigenous Peoples ("**UNDRIP**"). The means and timelines associated with UNDRIP's implementation by government is ongoing and, in some instances, uncertain: additional processes have been and are expected to continue to be created, or legislation amended or introduced associated with project development and operations, further increasing uncertainty with respect to project regulatory approval timelines and requirements.

## **RISK FACTORS**

The Corporation is subject to both risks that directly affect its business and operations, as well as indirect risks that impact third parties or industry generally. 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, the business of third parties with whom the Corporation conducts business and the crude oil and natural gas business generally.

The acquisition, exploration and development of crude oil, condensate, other NGL and natural gas properties and the production, transportation and marketing of crude oil, condensate, other NGL and natural gas involves many risks, which may influence the ultimate success of the Corporation. If any of the risks set out below materialize, the Corporation's business, financial condition, results of operations, prospects, cash flow and reputation may be adversely affected, which may, in turn, reduce or restrict the Corporation's ability to pay dividends and may materially affect market prices of the Corporation's securities.

While the Corporation realizes these risks cannot be eliminated, it is committed to monitoring and mitigating these risks.

### **Credit Facilities Risks**

The amounts authorized under the First Lien Credit Facilities is dependent on the borrowing base determined by the lenders thereunder. The Corporation is required to comply with covenants under the



Credit Facilities which may 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. Even if the Corporation is able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to the Corporation. If the Corporation is unable to repay amounts owing under the Credit Facilities, the lenders under the Credit Facilities could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. 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 impact of the SCC decision in the Redwater Decision case on lending practices in the crude oil and natural gas sector and actions taken by secured creditors and receivers/trustees of insolvent borrowers has the effect of adjusting lending practices to account for end-of-life obligations that were thought to be subordinate to secured debt and will be subject to prior satisfaction of abandonment and restoration claims which may not be capable of quantification at the time credit is advanced. See "*Industry Conditions – Liability Management Rating Programs*".

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. A material decline in commodity prices could reduce the Corporation's borrowing base, reducing the funds available to the Corporation under the Credit Facilities. This could result in the requirement to repay a portion, or all, of the Corporation's bank indebtedness.

### **Commodity Prices, Markets and Marketing**

The Corporation's revenue, operating results and financial condition depend substantially on the prevailing prices for crude oil and natural gas and the Corporation's ability to successfully market its oil and natural gas production from its properties. Numerous factors beyond the Corporation's control do, and will continue to, affect the marketability and price of crude oil and natural gas acquired, produced or discovered by the Corporation.

The Corporation's ability to market crude oil and natural gas may depend upon the ability to acquire capacity in pipelines that deliver oil, NGL and natural gas to commercial markets or contract for the delivery of crude oil and NGL by rail (see "*Industry Conditions – Pricing and Marketing in Canada*" and "*Risk Factors – Weakness and Volatility in the Petroleum and Natural Gas Industry*"). Numerous factors beyond the Corporation's control do, and will continue to, affect the marketability and price of crude oil and natural gas acquired, produced, or discovered by the Corporation:

- 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 crude oil and natural gas.

Crude 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, 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, the war in Ukraine, the outbreak of pandemic or contagious diseases, such as COVID-19 and its impact on the supply of, and demand for, crude oil, NGL and natural gas, global crude oil, NGL and natural gas inventory levels, weather conditions affecting supply and demand, overall domestic and global economic conditions, currency fluctuations, social attitudes or policies affecting energy consumption and energy supply, domestic and foreign governmental regulations, including environmental regulations, climate change regulations and taxation, the effects of energy conservatism efforts and GHG reduction measures, the price, availability and acceptance of alternative energies, including renewable energy, and ongoing credit and liquidity concerns. Prices for crude oil and natural gas are also subject to the availability of foreign markets and the ability to access such markets. A material decline in prices or a continued low crude oil and natural gas price environment could result in a reduction of the Corporation's anticipated production revenue.

The economics of producing from some wells may change because of lower prices, which could result in reduced production of crude oil or natural gas and a reduction in the volumes of the Corporation's reserves. The Corporation may also elect not to produce from certain wells at lower prices, which, in turn, would reduce the Corporation's production revenues. Any substantial and extended decline in or continued low crude oil and natural gas prices may impact the Corporation's carrying value of its reserves, royalty revenues, profitability and cash flow which may have a material adverse effect on the Corporation's business and financial condition. See "*Industry Conditions – Pricing and Marketing in Canada – Transportation Constraints and Market Access*" and "*Risk Factors – Weakness and Volatility in the Petroleum and Natural Gas Industry*".

Volatile crude 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 crude oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on the value or terms of such arrangements. Price volatility also makes it difficult to budget for and project the return on potential acquisitions, divestitures or leasing opportunities.

Lower commodity prices may also affect the volume and value of the Corporation's reserves, rendering certain reserves uneconomic for development. The Corporation's reserves at December 31, 2023 are estimated using forecast prices and costs. If crude oil and natural gas prices decrease, the Corporation's reserves may be substantially reduced as economic limits of developed reserves are reached earlier and undeveloped reserves become uneconomic at such prices. Even if some reserves remain economic at lower price levels, sustained low prices may compel the Corporation to re-evaluate its development plans and reduce or eliminate various projects with marginal economics.

In addition, lower commodity prices may restrict the Corporation's cash flow resulting in less funds being available to fund the Corporation's capital expenditure programs. The Corporation's capital expenditure plans are impacted by the Corporation's cash flow. 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.

Additionally, 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 its crude oil and natural gas assets on its balance sheet and the recognition of an impairment charge on its income statement.

## Exploration, Development and Production Risks

Crude 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 crude oil and natural gas reserves, as well as to acquire additional crude oil and natural gas assets to contribute to additional crude oil, natural gas and NGL reserves. A future increase in the Corporation's reserves will also depend on the ability of the Corporation to encourage further exploration on and development of its existing properties and its ability to select and acquire suitable producing properties or prospects. Without the continual addition of new reserves, the Corporation's existing reserves and production therefrom will decline over time as the Corporation produces from such reserves. There is no assurance that the Corporation will be able to continue to find satisfactory properties to acquire or participate in. Moreover, management may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participations uneconomic. There is also no assurance that the Corporation will discover or acquire further commercial quantities of crude oil and natural gas.

Future crude oil and natural gas exploration may involve unprofitable efforts from dry wells or 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, which may result in decreased activities and therefore less revenue to the Corporation.

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 and the shutting-in 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 production, which may reduce the Corporation's revenue.

Crude 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 crude oil and natural gas wells, production facilities, other property, the environment and cause personal injury or threaten wildlife. Particularly, the Corporation may explore for and produce sour natural 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.

Crude 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 negative or 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 and business interruption insurance in an amount that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event, the Corporation could incur significant costs. See "*Risk Factors – Insurance*".

## Political Uncertainty

In the last several years, the United States, the Middle East and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. Since the 2016 U.S. presidential election, the American administration has withdrawn the United States from the Trans-Pacific Partnership (TPP) and the United States Congress has passed sweeping tax reform, which, among other things, significantly reduces United States corporate tax rates. This has affected the competitiveness of other jurisdictions, including Canada. The United States has not indicated any intention to rejoin the TPP but could try to negotiate stronger labour and environmental standards. The United States will be subject to a presidential election in the fall of 2024 which may lead to a change in administration which could have an impact on the current political agenda and policies of the United States.

Additionally, on January 20, 2021, the Biden administration announced its decision to revoke the federal permit granted by the former administration for the Keystone XL Pipeline, which overturned a comprehensive regulatory process that lasted more than a decade. In addition, NAFTA has been replaced with the USMCA. This has affected the competitiveness of other jurisdictions, including Canada. On January 25, 2021, the Biden administration signed an executive order with respect to stringent new Made-In-America rules for the U.S. government and has indicated that the exceptions to such rules will be very limited. The effects on the USMCA and the Canada-U.S. supply chain have not yet been significant but future potential impacts are unknown. Further, it is unclear exactly what other actions the United States administration, or incoming administration, will implement, and if implemented, how these actions may impact Canada and in particular the petroleum and natural gas industry. Any actions taken by the current United States administration may have a negative impact on the Canadian economy and on the businesses, financial condition, results of operations, prospects and the valuation of Canadian crude oil and natural gas companies, which could also negatively impact the Corporation, which negative impact could prove to be material over time.

In addition to the political disruption in the United States, the long-term impacts of the United Kingdom's exit from the European Union remain unforeseen, especially in a post-pandemic era. 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, including the ongoing military conflict in Israel, West Bank and Gaza Strip. To the extent that certain political actions taken in North America, Europe, the Middle East and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement, costs for goods and services required for the Corporation's business could increase and access to skilled labour could decrease, negatively impacting the Corporation's business, financial condition, results of operations, prospects and the market value of its Common Shares, which negative impact could prove to be material over time.

Beginning in November 2021, Russia began to amass troops along the Ukrainian border, heightening military tension in Eastern Europe. In February 2022, Russia sent troops into pro-Russian separatist regions in Ukraine, which has resulted in continued and ongoing conflict in Ukraine to date. Ongoing military tensions between Russia and Ukraine have the potential to threaten supply of oil and gas from the region and impact demand from other European countries as well as the possibility that other nations will impose certain tariffs and restrictions on oil from Russia. The long-term impacts of the tension between Russia and the Ukraine remains unclear, including the responses from other nations globally.

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 petroleum and natural gas industry including the balance between economic development and environmental policy. Continued uncertainty and delays, including a temporary shutdown due to flooding in British Columbia and wildfires in Alberta have led to

decreased investor confidence, increased capital costs and operational delays for producers and service providers operating in the jurisdictions where the Corporation's operations are located.

Following former Alberta Premier Jason Kenney's resignation on May 18, 2022, Danielle Smith was elected as Premier on October 11, 2022. Shortly after her appointment, Premier Smith introduced a bill to implement the Sovereignty Act. The Sovereignty Act was passed on December 8, 2022 and received Royal Assent on December 15, 2022. The Sovereignty Act, amongst other things, enables the Government of Alberta to choose which federal legislation, policies or programs it will enforce in Alberta, providing an overriding right to not enforce those which the Government of Alberta deems to be "harmful" to Alberta's interests or infringe on the Federal Constitution and its division of powers. The Sovereignty Act has been opposed by many, including the National Democratic Party and various Indigenous groups who have expressed concern as to how the Sovereignty Act will affect Indigenous rights and consultation obligations in Alberta. In November 2023, Ms. Smith introduced a resolution to invoke the Sovereignty Act to challenge the federal government's requirement for a net-zero electricity grid by 2035. It is unclear what the effect the Sovereignty Act will have on Alberta, including the petroleum and natural gas industry Alberta businesses and its federal and interprovincial relationships, particularly in-light of its recent use, and what impact it may have on the application of other federal legislation in Alberta, such as the GGPPA and the way in which the Alberta Government may address any legislative and policy gaps created. Although the Sovereignty Act has not yet been challenged in court, particularly following its recent application, it is possible the Sovereignty Act's constitutionality will be challenged.

The federal government was re-elected in 2019, but in a minority position. Another federal election was held on September 20, 2021 and the federal government was re-elected again 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 petroleum and natural gas industry. The minority federal government will also be required to rely on the support of the other elected parties to remain in power, which provides less stability and may lead to an earlier subsequent federal election. Lack of political consensus, at both the federal and provincial government 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 petroleum and natural gas industry, which effect could prove to be material over time. See "*Industry Conditions – Climate Change Regulation*", "*Industry Conditions – Pricing and Marketing in Canada – Transportation Constraints and Market*", and "*Industry Conditions – The United States Mexico Canada Agreement and other Trade Agreements*".

## **Global Financial Markets**

The market events and conditions that transpired in recent years, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have, among other things, caused significant volatility in commodity prices. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors negatively impacted enterprise valuations and impacted the performance of the global economy. Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties regarding the supply and demand fundamentals for petroleum products due to the current state of the world's economies, actions taken by OPEC, the ongoing risks facing the North American and global economies and increased supplies of crude oil which may be created by the application of new drilling technology to unconventional resource plays.

## **Exposure to Widespread Pandemic and Risks Related Thereto**

Pandemics, epidemics or outbreaks, including COVID-19, remain a risk for the Corporation, and the ultimate impact of a pandemic is highly uncertain and subject to change. A pandemic and the corresponding measures we take to protect the health and safety of our staff and the continuity of our business may result in new legal challenges and disputes, including, but not limited to, litigation involving contract parties or employees and class action claims. Actions taken by various levels of government and health authorities in the event of a pandemic, epidemic or outbreak may result in a reduction in the demand for, and prices of, commodities that are closely linked to our financial performance and may negatively impact our business, results of operations and financial condition. The Corporation may also be exposed to human capital risks due to issues related to health and safety matters, and other environmental stressors as a result of measures which may be implemented in response to a pandemic.

In virtually all aspects of our business and strategy, our view of risks is not static as our business activities expose us to a variety of risks. We actively manage our risks to help protect and enable our business and future prospects. Additionally, we continue to evaluate the impacts, and any potential residual impacts that COVID-19 had and may continue to have on our business, including the impact on our principal and emerging risks, operational and reputational risks as well as credit, market and liquidity and funding risks and ESG risks. For further details on our risks, refer to the detailed risk factors below and throughout this AIF.

## **Inflation and Cost Management**

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

The cost or availability of oil and gas field equipment may adversely affect the Corporation's ability to undertake exploration, development and construction projects.

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

## **Weakness and Volatility in the Petroleum and Natural Gas Industry**

Market events and conditions, including global excess crude oil and natural gas supply, actions taken by OPEC+, sanctions against, and civil unrest in, Iran and Venezuela, Russia and the Ukraine, Israel and the West Bank and Gaza Strip; slowing growth in China and emerging economies; market volatility and disruptions in Asia; weakening global relationships; conflict between the United States and Iran; isolationist and punitive trade policies; increased United States shale production; sovereign debt levels; world health emergencies (including the outbreak of pandemic or contagious diseases, such as COVID-19); climate change concerns and political upheavals in various countries including growing anti-fossil fuel sentiment, have caused significant weakness and volatility in commodity prices. Following extreme supply/demand imbalance in 2020, the crude oil and natural gas industry rebounded strongly throughout 2021, with oil prices reaching their highest levels in six years. However, the ongoing war in the Ukraine and price caps and sanctions on oil from Russia have impacted demand and oil prices throughout the latter half of 2022

which continued throughout 2023. It is anticipated that the petroleum and natural gas industry will experience more pressure from investors to take meaningful strides towards combating climate change in the upcoming years, including diversifying their energy portfolios. These events and conditions have caused a significant decrease in the valuation of crude oil and natural gas companies and a decrease in confidence in the petroleum and natural gas industry. Such difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. See "*Industry Conditions - Royalties and Incentives*", "*Industry Conditions - Regulatory Authorities and Environmental Regulation*" and "*Industry Conditions - Climate Change Regulation*".

In addition, 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 petroleum and natural gas industry in Western Canada and cross-border with the United States has led to additional downward price pressure on crude oil and natural gas produced in Western Canada. The resulting price differential between Western Canadian Select crude oil, Brent and West Texas Intermediate crude oil has created uncertainty and reduced confidence in the petroleum and natural gas industry in Western Canada. See "*Industry Conditions – Pricing and Marketing in Canada – Transportation Constraints and Market Access*".

### **Project Risks**

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

- availability and proximity 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 and natural disasters, including fire, drought and flooding;
- availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- political uncertainty;
- availability and productivity of skilled labour;
- environmental and Indigenous activism that potentially results in delays or cancellations of projects;
- litigation and judicial interpretation and application of laws, including with respect to indigenous rights and historical treaties; and
- regulation of the petroleum 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, and may be unable to effectively market the crude oil, NGL and natural gas that it produces.

## **Reliance on Skilled Workforce and Key Personnel**

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.

There is competition for qualified personnel in the petroleum and natural gas industry 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. 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, which negative impact could prove to be material over time. In addition, the Corporation could experience increased costs to retain and recruit these professionals.

## **Operational Dependence**

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 business, financial condition, results of operations and prospects. 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, companies that may operate some of the assets in which the Corporation has an interest may be in or encounter 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 recourse 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 to it 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 effect on the Corporation's financial and operational results.

## **Alternatives to and Changing Demand for Petroleum Products**

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to crude oil and natural gas, and technological advances in fuel economy and renewable energy generation systems could reduce the demand for crude oil, natural gas and liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels, commitments to carbon reduction 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 crude oil and natural gas products. The Corporation cannot predict the impact of changing demand for crude oil and natural gas products, and any major changes may have a negative impact on the Corporation's business and financial condition by decreasing the Corporation's revenues, limiting its access to capital and decreasing the value of its assets.

### **Variations in Foreign Exchange Rates and Interest Rates**

World crude 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 crude oil and natural gas. Material increases in the value of the Canadian dollar relative to the United States may indirectly negatively affect the Corporation's revenues, as revenues received by Canadian producers and, similarly, royalties payable to the Corporation, could decrease. Accordingly, exchange rates between Canada and the United States could affect the future value of the Corporation's reserves as determined by independent reserves evaluators. Where the Corporation engages in risk management activities related to foreign exchange rates, there is a potential 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 activities and the cash available to pay dividends, and could negatively impact the market price of the Common Shares, which negative impact could prove to be material over time.

### **Gathering and Processing Facilities, Pipeline Systems and Rail**

The Corporation delivers its products through gathering, processing facilities and pipeline systems, none of which are owned by the Corporation. The amount of crude oil and natural gas produced by the Corporation 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 petroleum and natural gas industry and limits the ability to transport produced crude oil and natural gas to market. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability of crude oil and natural gas companies to export crude oil and natural gas, and could result in the inability of third parties to realize the full economic potential of the produced crude oil or natural gas or a reduction of the price offered for the Corporation's production. Unexpected shutdowns or curtailment of capacity of pipelines for maintenance or integrity work, natural disasters and environmental conditions, or because of actions taken by regulators could also affect third parties' production and operations which may have a material adverse effect on the Corporation's business and financial condition. As a result, producers have considered rail lines as an alternative means of transportation.

Future pipeline projects may be terminated for reasons such as a failure to obtain government and/or regulatory support or approval. The direct impact that the termination of such projects will have on the Corporation is unknown.

Federal and various provincial governments have been active in recent years in their support for and opposition to major infrastructure projects in Canada, leading to increased awareness and challenges to interprovincial and international infrastructure projects. In the fall of 2023, the SCC found the designated project scheme under IAA to be unconstitutional and the federal government is currently in the process of revising the IAA to make it compliant. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*". The impact of the new federal regulatory scheme, including the regime to be implemented under the revised IAA, and in the interim, the application of the Interim Guidance, on proponents and the timing for receipt of approvals of major projects is unknown. Projects which are subject to an impact assessment under both provincial and federal legislation, will likely be subject to a robust assessment of

the environmental, social, health, economic and cultural impacts of a proposed project subject to the legislation, as well as the effects of projects on Indigenous peoples and their rights which may lead to longer periods to conduct the assessment and potentially more opportunities for public engagement and consultation. A portion of our production may, from time to time, be processed through facilities owned by third parties over which the Corporation, have no 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 ability of the Corporation 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.

The Corporation has certain long-term take-or-pay commitments to deliver products through third-party owned infrastructure which creates a financial liability and there can be no assurance that future volume commitments will be met which may adversely affect the Corporation's financial condition and cash flow from operating activities. Deliverability uncertainties related to the distance the Corporation's reserves are to pipelines, processing and storage facilities, operational problems affecting pipelines and facilities, as well as government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of crude oil and natural gas and other aspects of the petroleum and natural gas industry may also affect the Corporation. See "*Risk Factors – Commodity Prices, Markets and Marketing*".

## **Regulatory**

The implementation of new regulations or the modification of existing regulations affecting the petroleum and natural gas industry could reduce demand for crude oil and natural gas and increase costs or make certain projects uneconomic, either of which could materially adversely affect the Corporation's business and financial condition. 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 petroleum and natural gas industry. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*", "*Industry Conditions – Pricing and Marketing in Canada – Transportation Constraints and Market Access*".

In order to conduct crude oil and natural gas operations, third-party lessees and/or operators will require regulatory permits, licences, registrations, approvals and authorizations from various governmental authorities at the provincial and federal level. There can be no assurance that the Corporation will be able to obtain all of the permits, licences, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake in the time required or on acceptable terms and conditions. Any failure to renew, maintain or obtain required permits, licences, registrations, approvals and authorizations or the revocation or termination of existing permits, licences, registrations, approvals and authorizations may disrupt such operations and could have a resulting material adverse effect on the Corporation's business and financial condition. In addition, certain federal legislation such as the *Competition Act* (Canada) 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*" and "*Industry Conditions – Liability Management Rating Programs*".

## **Environmental**

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 municipal 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 petroleum 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. 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 on such lessees or operators, 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 crude oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. The Corporation believes that it is in material compliance with current applicable environmental legislation; however, 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 negative effect on the Corporation's business and financial condition, which negative effect could prove material over time.

Stakeholders, the public and provincial and federal governments are becoming increasingly concerned about habitat and species protection, including degradation to biodiversity caused by economic activity. Accordingly, governments at various levels are increasing the rigour of existing acts and regulations and issuing changes aimed at improving environmental protection. The Corporation and its employees, consultants and operators may disturb the surrounding biodiversity of its properties with the requirement for earth moving and the footprint of crude oil and natural gas operations. This may result in impacts to flora and fauna, including species at risk. Operations on the Corporation's properties may also be affected by conditions or restrictions on operations caused by wildlife habitat and migration patterns, endangered species or species at risk, and vegetation located on the Corporation's properties. The Corporation may fail to achieve necessary permits or be subject to penalties or litigation if they cause habitat destruction or otherwise fail to mitigate impacts on biodiversity on the Corporation's properties. There is no assurance that the Corporation will effectively limit habitat destruction or mitigate the impacts on biodiversity on its properties. If the Corporation fails to do so, there may be decreased activities on the Corporation's properties, which could have an adverse effect on the Corporation's business and financial condition. See *"Industry Conditions - Regulatory Authorities and Environmental Regulation"*.

## **Liability Management**

Alberta 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. Alberta and the AER continue to implement the AB LMF, completing the remaining amendments to the necessary directive and regulations to entirely phase-out the AB LMR Program. The implementation of the AB LMF or other changes to the requirements of liability management programs may result in significant increases to the security that must be posted by the Corporation, increased and more frequent financial disclosure obligations or may result in the denial of licence or permit transfers, which could impact the availability of capital to be spent by the Corporation which could in turn materially adversely affect the Corporation's business and financial condition. The impact and consequences of the Redwater Decision on the AER's rules and policies, lending practices in the petroleum and natural gas industry 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. In addition, the AB LMF may prevent or interfere with the Corporation's ability to acquire or dispose of assets, as both the vendor and the purchaser of crude 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. See "*Industry Conditions – Liability Management Rating Programs*".

## **Royalty Regimes**

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 could impact the financial condition of the Corporation impacting future capital investment which could reduce the Corporation's business, financial condition, results of operations and prospects. See "*Industry Conditions – Land Tenure – Royalties and Incentives*".

## **Climate Change**

Global climate issues continue to attract public and scientific attention. Numerous reports, including reports from the Intergovernmental Panel on Climate Change, have engendered concern about the impacts of human activity, especially hydrocarbon combustion, on global climate issues. In turn, increasing public, government, and investor attention is being paid to global climate issues and to emissions of GHG, including emissions of carbon dioxide and methane from the production and use of oil, liquids and natural gas. The majority of countries across the globe, including Canada and the United States, have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In addition, during the course of the 2021 United Nations Climate Change Conference in Glasgow, Scotland, Canada's Prime Minister Justin Trudeau made several pledges aimed at reducing Canada's GHG emissions and environmental impact. Subsequent conferences have generally reconfirmed the prior commitments made by the countries who participate in the United Nations Climate Change Conferences.

### *Transition Risks*

Foreign and domestic governments continue to evaluate and implement policy, legislation, and regulations focused on restricting emissions commonly referred to as GHG emissions and promoting adaptation to climate change and the transition to a low-carbon economy. It is not possible to predict what measures foreign and domestic governments may implement in this regard, nor is it possible to predict the requirements that such measures may impose or when such measures may be implemented.

However, international multilateral agreements, the obligations adopted thereunder and legal challenges concerning the adequacy of climate-related policy brought against foreign and domestic governments may accelerate the implementation of these measures. Given the evolving nature of climate change policy and the control of GHG emissions and resulting requirements, including carbon taxes and carbon pricing schemes implemented by varying levels of government, it is expected that current and future climate change regulations will have the effect of increasing the operating expenses, and, in the long-term, potentially reducing the demand for oil, liquids, natural gas and related products, resulting in a decrease in the Corporation's profitability and a reduction in the value of its assets. See "*Risk Factors – Non-Governmental Organizations*" and "*Risk Factors – Reputational Risk*". Claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance under certain laws or that such energy companies provided misleading disclosure to the public and investors of current or future risks associated with climate change. As a result, individuals, government authorities, or other organizations may make claims against oil and natural gas companies, including the Corporation, for alleged personal injury, property damage, or other potential liabilities. While the Corporation is not a party to any such litigation or proceedings, it could be named in actions making similar allegations. An unfavorable ruling in any such case could adversely affect the demand for and price of securities issued by the Corporation, impact its operations and have an adverse impact on its financial condition.

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

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

### *Physical Risks*

Based on the Corporation's current understanding, the potential physical risks resulting from climate change are long-term in nature and associated with a high degree of uncertainty regarding timing, scope, and severity of potential impacts.

Many experts believe global climate change could increase extreme variability in weather patterns such as increased frequency of severe weather, rising mean temperature and sea levels, and long-term changes in precipitation patterns. Extreme hot and cold weather, heavy snowfall, heavy rainfall, and wildfires may restrict the ability of the Corporation to access its properties and cause operational difficulties, including damage to equipment and infrastructure. Extreme weather may also increase the risk of personnel injury as a result of dangerous working conditions for the Corporation, its employees and contractors.

### *Chronic Physical Climate Change Risks*

The Corporation's operations and activities associated with the Corporation's projects and assets emit GHGs 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 negative effect on the Corporation's business, financial condition, results of operations and prospects, which negative effects could prove material over time. There is no guarantee the current provincial regimes in place will continue to meet federal stringency

requirements and their continued application is subject to achieving the stringency standards as required by the federal government.

Climate change has been linked to long-term shifts in climate patterns, including sustained higher temperatures. As the level of activity in the Canadian petroleum and natural gas industry is influenced by seasonal weather patterns, long-term shifts in climate patterns pose the risk of exacerbating operational delays and other risks posed by seasonal weather patterns. In addition, long-term shifts in weather patterns such as water scarcity, increased frequency of storm and fire and prolonged heat waves may, among other things, require 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, which may in turn have a negative effect on the Corporation's production which negative effect could prove material over time. 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.

Concerns over climate change, fossil fuels, GHG emissions and water and land-use could lead to reduced demand for the crude oil, natural gas and NGLs, which would have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. See "*Risk Factors – Alternatives to and Changing Demand for Petroleum Products*".

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 crude 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 impairments for financial statement purposes. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*", "*Industry Conditions – Climate Change Regulation*", "*Risk Factors – Non-Governmental Organizations*", "*Risk Factors – Reputational Risk*" and "*Risk Factors – Changing Investor Sentiment*".

#### *Acute Physical Climate Change Risks*

Climate change has been linked to extreme weather conditions. Extreme hot and cold weather, heavy snowfall, heavy rainfall and wildfires may restrict or could interfere with the Corporation's operations, increasing costs and negatively impacting the lessee or operator's production.

Over the last several years, certain areas of British Columbia, Alberta and Saskatchewan have been negatively impacted by wildfires and, most recently with extreme flooding in British Columbia, causing temporary interruption to both pipeline systems and railway lines. Extreme weather conditions may lead to disruptions in the Corporation's ability to transport produced crude oil and natural gas as well as goods and services in their supply chains and meet demand due to temporary interruptions.

Certain of the Corporation's operations are located in locations that are proximate to forests and rivers and a wildfire or flood, respectively, may lead to significant downtime and/or damage to such assets which may affect production. At this time, the Corporation is unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting the Corporation's operations.

#### **Natural Disasters, Terrorist Act, Civil Unrest, Pandemics and Other Disruptions and Dislocations**

Upon the occurrence of a natural disaster, or upon an incident of war, riot or civil unrest, the impacted country, province, 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, COVID-19), civil unrest (including the most recent protests and

railway blockades in Canada) 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.

### **Hydraulic Fracturing**

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under high pressure into rock formations to stimulate the production of crude oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of crude 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 costs of compliance and doing business as well as delay the development of crude 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 crude oil and natural gas that is ultimately produced from the Corporation's reserves and, therefore, could materially adversely affect the Corporation's business, financial condition, results of operations and prospects.

Water is an essential component of the Corporation's drilling and hydraulic fracturing processes. Limitations or restrictions on the Corporation's ability to secure sufficient amounts of water (including limitations resulting from natural causes such as drought), could materially and adversely impact its operations. Severe drought conditions can result in local water authorities to take steps to restrict the use of water in their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. If the Corporation is unable to obtain water to use in its operations from local sources, it may need to be obtained from new sources and transported to drilling sites, resulting in increased costs which could have a material adverse effect on its financial condition, results of operations and cash flows.

Additionally, the Corporation must dispose of the fluids produced from crude oil, NGL and natural gas production operations, including produced water, which it does directly or through the use of third-party vendors. The legal requirements related to the disposal of produced water into a non-producing geologic formation by means of underground injection wells are subject to change based on concerns of the public or governmental authorities regarding such disposal activities. See "*Risk Factors – Disposal of Fluids Used in Operations*".

Another consequence of seismic events may be lawsuits alleging that disposal well operations have caused damage to neighboring properties or otherwise violated laws and regulations regarding waste disposal. These developments could result in additional regulation and restrictions on the use of injection wells by the Corporation or by commercial disposal well vendors that the Corporation may use from time to time to dispose of produced water. Increased regulation and attention given to induced seismicity could also lead to greater opposition, including litigation to limit or prohibit oil and natural gas activities utilizing injection wells for produced water disposal.

Any one or more of these developments may result in the Corporation or its vendors having to limit disposal well volumes, disposal rates and pressures or locations, or require the Corporation or its vendors to shut down or curtail the injection of produced water into disposal wells, which events could have a material adverse effect on the Corporation's business, financial condition and results of operations.

### *Alberta*

Seismic events are common in certain parts of Alberta and are generally clustered around the municipalities of Red Deer, Cardston, Fox Creek and Rocky Mountain House. Due to notable seismic activity reported around Fox Creek and the Red Deer region, the AER introduced seismic monitoring and reporting

requirements for hydraulic fracturing operators in the Duvernay formation in the Fox Creek area in February 2015 and subsequently in the Red Deer region in December 2019. 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. Further, the AER continues to monitor seismic activity around the province and may extend these requirements to other areas of the province if necessary.

## **Energy Transition**

Globally, there is an increasing focus on transitioning to a low-carbon economy resulting in a number of policies and initiatives designed to shift resources and investment away from fossil fuels towards low carbon sources. This includes government regulations that restrict the production and consumption of fossil fuels such as zero emission vehicle mandates, prohibitions on plastic use, and fuel efficiency standards. Government subsidies directed towards new low-carbon technologies or to businesses providing products and services that reduce consumer demand for fossil fuels may also result in a broader reduction in the global economy's reliance on fossil fuels. In addition, shifting consumer preferences towards low-carbon products and services are also driving investment in technologies and products that reduce fossil fuel consumption. The Corporation is constantly evaluating its options with respect to increasing environmental efficiency through its operations. However, there can be no assurances that the Corporation will be able to predict any such market trends or consumer preferences. Accordingly, there is a risk that the nature of the global energy transition materially adversely affects the Corporation's business and financial condition.

## **Waterflood**

The Corporation may undertake or intend 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 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 they may not be able to undertake waterflooding activities, which may reduce the amount of crude oil and natural gas that the Corporation will ultimately receive 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 business, financial condition, results of operations and prospects.

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

The safe disposal of the hydraulic fracturing fluids (including the additives) and water recovered from crude 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 costs of compliance the Corporation which may impact the economics of certain projects and in turn impact activity levels and new capital spending.

## **Title to Assets**

Although title reviews may be conducted prior to the purchase of fee simple mineral title interests or the commencement of drilling wells, such reviews do not guarantee or certify that a defect in the chain of title will not arise to defeat the Corporation's claim. The Corporation's actual interest may, therefore, vary from the records previously maintained by the prior owners. If a title defect does exist, it is possible that the



Corporation may lose all or a portion of the properties to which the title defect relates, which could materially adversely affect the Corporation's business, financial condition, results of operations and prospects.

There may be valid challenges to title, or proposed legislative changes which affect title, to the oil and natural gas properties that the Corporation controls that, if successful or made into law, could impair our interests in the oil and natural gas properties that it controls and impact the Corporation's business, financial condition, results of operations and prospects.

### **Non-Governmental Organizations**

The petroleum and natural gas industry may, at times, be subject to public opposition. The oil and natural gas industry has become increasingly politically polarizing in Canada, which has resulted in civil disobedience surrounding oil and natural gas development, particularly with respect to infrastructure projects. 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 which may include Indigenous groups, landowners, environmental interest groups (including those opposed to crude 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, and delays in, challenges to, or the revocation of regulatory approvals, permits and/or licences, and direct legal challenges, including the possibility of climate-related litigation (see "*Industry Conditions – Pricing and Marketing in Canada – 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 significant and unanticipated capital and operating expenditures which may negatively impact the Corporation's business, financial condition, results of operations and prospects, which negative impact could prove to be material over time.

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

Crude 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 areas where such activities will be conducted. The availability of such material and equipment is limited. The oil and natural gas industry is cyclical in nature and is prone to shortages of supply of equipment and services, including drilling rigs, geological and geophysical services, engineering and construction services, major equipment items for infrastructure projects and construction materials generally. These materials and services may not be available when required at reasonable prices. An increase in demand or cost, or a decrease in the availability of such materials and equipment may impede the Corporation's operations and may delay such exploration, development and operating activities, which, in turn, could materially adversely affect the Corporation's business and financial condition.

### **Carbon Pricing Risk**

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, which was upheld by the SCC as constitutional, currently applies in provinces and territories without their own system that meets federal stringency standards and provinces with their own system are subject to continued compliance with the federal system. There is no guarantee that a province with a system that currently applies will meet, or continue to meet federal stringency standards. See "*Industry Conditions – Climate Change Regulation*".

Any taxes placed on carbon emissions may have the effect of decreasing the demand for crude oil and natural gas products and at the same time, increasing the operating expenses of crude oil and natural gas companies, each of which may have a material adverse effect on the Corporation's revenue.

Further, the imposition of carbon taxes puts companies at an economic disadvantage with its counterparts who operate in jurisdictions where there are less costly carbon regulations.

### **Expansion into New Activities**

The operations and expertise of the Corporation's management are currently focused on oil and natural gas production, exploration and development in the Corporation's Sparky, Southeast Saskatchewan, Manitoba, Carbonates, Valhalla, Shaunavon and Minors regions. In the future, the Corporation may acquire or move into new industry-related activities or new geographical areas or may acquire different energy-related assets, and as a result, the Corporation may face unexpected risks or alternatively, the Corporation's 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 condition being adversely affected.

### **Insurance**

Although the Corporation maintains insurance in accordance with industry standards to address certain risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of 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 or retentions 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.

### **Expiration of Licences and Leases**

Certain of the Corporation's properties are held in the form of licences and leases and working interests in licences and leases held by others. If the Corporation or the holder of the licence or lease fails to meet the specific requirements 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 these licences or leases or the working interests relating to a licence or lease may impair certain of the Corporation's properties and in turn may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

### **Litigation**

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 property damage, personal injury, property tax, land rights, royalty rights, access rights, environmental issues and lease or contract disputes. The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty, may be determined adversely to the Corporation and could have a material adverse effect on the Corporation's business, financial condition and funds from 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 effect on the Corporation's business and financial condition.

## **Indigenous Claims**

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 negative effect on the Corporation's business, financial condition, results of operations and prospects, which negative effect could prove to be material over time. In addition, the process of addressing such claims, regardless of the outcome, is expensive and time consuming and could result in delays which could have a negative effect on the Corporation's business, financial condition, results of operations and prospects, which negative effect could prove to be material over time.

Moreover, in recent years there has been increasing litigation regarding historical treaties with Indigenous peoples in Canada. Judicial interpretation of such historical treaties, and in particular the rights granted thereunder to Indigenous nations to manage and use the lands in a manner consistent with their ancestral practices, may impact future resource and industrial development in and around these lands. While the potential impact of current and future judicial decisions is uncertain at this time, it is possible that such decisions may have a negative effect on the Corporation's business, financial condition, results of operations and prospects, which negative effect could prove to be material over time.

## **Failure to Realize Anticipated Benefits of Acquisitions and Dispositions**

The Corporation considers acquisitions and dispositions of 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. Acquisitions of oil and natural gas properties or companies are based in large part on engineering, environmental and economic assessments. These assessments include a number of assumptions regarding such factors as recoverability and marketability of oil and natural gas, environmental restrictions and prohibitions regarding releases and emissions of various substances, future prices of oil and natural gas, future operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the Corporation. All such assessments involve a measure of geological, engineering, environmental and regulatory uncertainty that could result in lower production and reserves or higher operating or capital expenditures than anticipated.

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. The Corporation may also enter into other industry-related activities or new geographical areas or acquire different energy-related assets that may result in unexpected or significantly increased risk to the Corporation, which could materially adversely affect the Corporation's business, financial condition, results of operations and prospects. Management continually assesses the value and contribution of the various properties and assets within its portfolio. In this regard, the Corporation may consider disposing of certain non-core assets in-order to focus its efforts and resources more efficiently. Depending on market conditions for such non-core assets, the Corporation may realize less on disposition of certain core assets than their carrying value on the financial statements of the Corporation.

## **Industry Competition**

The petroleum and natural gas industry is competitive throughout its lifecycle. The Corporation competes with numerous other entities in the search for, the acquisition of and the development of petroleum and natural gas properties, access to drilling and service rigs and other equipment, access to transportation,

access to skilled and technical operating personnel and in the marketing of petroleum and natural gas. Other companies may have access to substantially greater financial resources, staff and facilities than those of the Corporation and who may have lower costs of, and better access to, capital.

The Corporation's ability to increase its reserves in the future will depend partially on its ability to explore and develop its present properties, but will also depend on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling.

### **Management of Growth and Integration**

The Corporation may be subject to both transition and growth-related risks, including capacity constraints and pressure on its internal systems and controls. In particular, the Corporation is responsible for managing a substantial number of land and title documents and related accounting functions that require significant employee resources. The ability of the Corporation to manage future growth and integration of additional lands, leases and acquisitions effectively requires it to continue to implement and improve financial and land systems and to expand, train and manage its employee base. The inability of the Corporation to deal with this integration and growth may have a negative effect on the Corporation's business, financial condition, results of operations and prospects, which negative effect could prove to be material over time.

### **Reserves Estimates**

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 AIF are estimates only. Generally, estimates of economically recoverable crude oil and natural gas reserves (including the breakdown of reserves by product type) and the future net cash flows from such estimated reserves which are based upon a number of variable factors and assumptions, such as:

- historical production from the properties;
- commodity prices;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures by the working interest owners thereon;
- marketability of crude 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 these reasons, estimates of the economically recoverable crude oil, natural gas and NGL 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 net production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof 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. Such variations could be material.

In accordance with applicable securities laws, Sproule, the Corporation's independent qualified 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 crude oil and natural gas, curtailments or increases in consumption by crude 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 crude oil, natural gas and NGL reserves will vary from the estimates contained in the Reserves Report and such variations could be material. The Reserves Report is effective as of December 31, 2023, with a preparation date of February 9, 2024, and, except as may be specifically stated or required by applicable securities laws, has not been updated and, therefore, does not reflect changes in reserves since that date.

### **Market Price of Common Shares**

The trading price of the securities of crude 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. This includes, but is not limited to, changing and in some cases, negative investor sentiment towards energy-related businesses. In recent years, the volatility of crude oil and natural gas commodity prices, and the securities of issuers involved in the crude oil and natural gas business, has increased due, in part, to the implementation of computerized trading and the decrease of discretionary commodity trading. Similarly, recent market prices in the securities of crude oil and natural gas issuers relative to other industry sectors have led to lower crude oil and natural gas representation in certain key equity market indices. The volatility, trading volume and market price of crude oil and natural gas have been impacted by increasing investment levels in passive funds that track major indices and only purchase securities included in such indices and subsequently dispose of those securities if they are excluded from such indices. In addition, many institutional investors, pension funds and insurance companies, including government sponsored entities, have implemented investment strategies increasing their investments in low-carbon assets and businesses while decreasing the carbon intensity of their portfolios through, among other measures, divestments. These factors have impacted the volatility and liquidity of certain securities and put downward pressure on the market 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.

### **Capital and Additional Funding Requirements**

The Corporation's cash flow from its properties may not be sufficient to fund its ongoing activities at all times, and from time to time the Corporation may require additional financing, which may include financing for the acquisition of crude oil and natural gas assets. Future capital and other expenditures will be financed out of cash generated from operations, borrowings and possible future equity issuances and the Corporation's ability to do so will be dependent on, among other factors: the overall state of the capital markets; commodity prices; the Corporation's credit rating (if applicable); commodity prices; interest 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. Due to the conditions in the petroleum and natural gas industry and/or 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. The current conditions in the petroleum and natural gas industry have negatively impacted the cost and/or ability of crude oil and natural gas companies to access additional financing.

There can be no assurance that debt or equity financing, or cash flow 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.

Alternatively, any available financing may be highly dilutive to existing shareholders. There is risk that if the economy and banking industry experience unexpected and/or prolonged deterioration, the Corporation's access to additional financing may be affected. The inability of the Corporation to access sufficient capital for its operations could cause the Corporation to, amongst other things, miss certain acquisition opportunities and may materially adversely affect the Corporation's business and financial condition.

### **Changing Investor Sentiment**

A number of factors, including the effects of the use of fossil fuels on climate change, GHG emissions reduction, the impact of crude 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 petroleum 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 crude oil and natural gas properties or companies tied to crude oil and natural gas or are reducing the amount of their investments of such entities over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices, including the use of environmental metrics in executive compensation. Developing and implementing such policies and practices can be costly 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 petroleum 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 Common Shares, 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 assets which may result in an impairment charge.

### **Evolving Corporate Governance, Sustainability and Reporting Framework**

The Corporation's business is subject to evolving corporate governance and public disclosure regulations that have increased both compliance costs and the risk of noncompliance, which could have an adverse effect on the price of the Corporation's securities. The Corporation is subject to changing rules and regulations promulgated by a number of governmental and self-regulated organizations, including the Canadian Securities administrators, the TSX and the Financial Accounting Standards Board. These rules and regulations continue to evolve in scope and complexity making compliance more difficult and uncertain. Further, the Corporation's efforts to comply with these and other new and existing rules and regulations have resulted in, and are likely to continue to result in, increased general and administrative expenses and a diversion of management time and attention from revenue-generating activities to compliance activities.

### **Reputational Risk**

The Corporation's business, financial condition, operations or prospects may be negatively impacted, which negative impact could prove to be material over time, as a result of any negative public opinion toward the Corporation or as a result of any negative sentiment toward or in respect of 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 crude 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 licences and increased costs and/or cost overruns.

Any environmental damage, loss of life, injury or damage to property caused by the Corporation's operations could damage the reputation of and, in turn, the Corporation, in the areas in which the Corporation operates. Negative sentiment towards the Corporation could result in a lack of willingness of governmental authorities to grant the necessary licences or permits for the Corporation to operate its business. In addition, negative sentiment towards the Corporation could result in the residents of the areas where the Corporation is doing business opposing further operations in the area by the Corporation. The Corporation's reputation could be affected by actions and activities of other corporations operating in the petroleum and natural gas industry, over which the Corporation has no control. If the Corporation, either directly or indirectly develops a reputation of having an unsafe workplace 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 crude oil and natural gas development and the possibility of climate related litigation against fossil fuel companies may indirectly harm the Corporation's reputation.

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.

### **Cost of New Technologies**

The petroleum and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other petroleum and natural gas companies may have greater financial, technical and personnel resources that allow them to implement and benefit from new technologies before the Corporation. 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 implements 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. In such case, the Corporation's business, financial condition, results of operations and prospects could be materially adversely affected. If the Corporation is unable to utilize the most advanced commercially available technology or is unsuccessful in implementing certain technologies, its business, financial condition, results of operations and prospects could also be materially adversely affected.

### **Dividends**

The amount of future cash dividends paid by the Corporation is subject to the discretion of the Board and may vary depending on a variety of factors and conditions existing from time to time, including, among other things, fluctuations in commodity prices; production levels; financial condition of the Corporation; results of operations; capital expenditure requirements; working capital requirements; operating costs; current and expected future levels of earnings; liquidity requirements; market opportunities; income taxes; debt repayments; legal, regulatory, and contractual constraints; the Corporation's risk management activities or programs; the Corporation's business plan, strategies and objectives; tax laws; foreign exchange rates; interest rates; and the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends. Depending on these and various other factors, many of which are beyond the control of the Corporation, the Corporation's dividend policy and, as a result, future cash dividends, could be reduced or suspended entirely, from time to time. The Credit Facilities may prohibit the

Corporation from paying dividends at any time at which a default or event of default has occurred and is continuing, or if a default or event of default would exist as a result of paying the dividend.

Over time, the Corporation's capital and other cash needs may change significantly from its current needs, which could affect whether the Corporation pays dividends and the amount of dividends, if any, it may pay in the future. If the Corporation continues to pay dividends at the current levels, it may not retain a sufficient amount of cash to finance external growth opportunities, meet any large unanticipated liquidity requirements or fund its activities in the event of a significant business downturn. The Board may amend, revoke or suspend the Corporation's dividend policy at any time. A decline in the market price, liquidity, or both, of the Common Shares could result if the Corporation reduces or eliminates the payment of dividends, which could result in losses to shareholders.

The market value of the Common Shares may deteriorate if cash dividends are reduced or suspended. Furthermore, the future treatment of dividends for tax purposes will be subject to the nature and composition of dividends paid by the Corporation and potential legislative and regulatory changes. Dividends may be reduced during periods of lower funds from operations, which may result from lower commodity prices and/or lower royalty production volumes, and any decision by the Corporation to finance capital expenditures using funds from operations.

To the extent that external sources of capital, including in exchange for the issuance of additional Common Shares, become limited or unavailable, the ability of the Corporation to make the necessary acquisitions to maintain or expand petroleum and natural gas reserves will be impaired. To the extent that the Corporation is required to use funds from operations to finance capital expenditures or property acquisitions, the cash available for dividends may be reduced.

#### **Foreign Exchange Risk on Dividends**

The Corporation's cash dividends are declared in Canadian dollars and may be converted in certain instances to foreign denominated currencies at the spot exchange rate at the time of payment. As a consequence, non-resident shareholders, and shareholders who calculate their return in currencies other than the Canadian dollar, are subject to foreign exchange risk. To the extent that the Canadian dollar strengthens with respect to their currency, the amount of the dividend will be reduced when converted to the shareholder's home currency.

#### **Additional Taxation Applicable to Dividends Paid to Non-Residents**

Cash dividends paid to a non-resident of Canada on Common Shares are subject to Canadian withholding tax at a rate of 25% unless the rate is reduced under the provisions of an applicable double taxation treaty. These taxes may be reduced pursuant to tax treaties between Canada and the non-resident shareholder's jurisdiction of residence. Where a non-resident is a United States resident entitled to benefits of the Canada-United States Income Tax Convention, 1980 and is the beneficial owner of the dividends then the rate of Canadian withholding tax is generally reduced to 15%. In addition, the country in which the non-resident shareholder is resident may impose additional taxes on such dividends. Any of these taxes may change from time to time.

#### **Hedging**

The Corporation may enter into hedging arrangements to fix interest rates applicable to the Corporation's debt. However, if interest rates decrease as compared to the interest rate fixed by the Corporation, the Corporation will not benefit from the lower interest rate.



The Corporation may enter into agreements to receive fixed prices on its crude oil and natural gas royalty production volumes, if any, to offset the risk of revenue losses if commodity prices decline.

Similarly, the Corporation may enter into agreements to fix the differential or discount pricing gap which exists and may fluctuate between different grades of crude oil, NGL and natural gas and the various market prices received for such products. 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, if the Corporation enters into hedging arrangements it may be exposed to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes;
- 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; and/or
- a sudden unexpected material event impacts crude 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.

### **Income Taxes**

The Corporation files all required income tax returns in order to be 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, such reassessment may have an impact on current and future taxes payable.

Income tax laws relating to the petroleum 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.

### **Issuance of Debt**

From time to time, the Corporation may finance its activities (including potential future crude oil and natural gas royalty asset acquisitions) in whole or in part with debt, which may increase the Corporation's debt levels above industry standards for peers of similar size. Additional debt financing 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.

### **Competition**

The petroleum and natural gas industry is highly competitive in all of its phases. The Corporation competes with numerous other entities for land, acquisition of reserves, access to drilling and service rigs and other

equipment, access to transportation and access to skilled technical and operating personnel, among other things. The Corporation's competitors include other companies who may have more financial resources, staff or political influence than the Corporation.

### **Conflicts of Interest**

Certain members of the Board and management are also, or may in the future be, directors or officers of other crude oil and natural gas companies, that may compete or be counterparties to agreements with the Corporation 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 and Corporation policies 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, or material transaction, or proposed material transaction, with the Corporation disclose their 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. The Corporation also has additional policies in place providing guidance as to how officers and directors are to manage conflicts of interest.

### **Breach of Confidentiality**

While discussing potential business relationships or other transactions with third parties, the Corporation may disclose confidential information relating to the business, operations or affairs of the Corporation. Although confidentiality agreements are generally signed by third parties prior to the disclosure of any confidential information by the Corporation, 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 solely in monetary 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.

### **Information Technology Systems and Cyber-Security**

The Corporation has become 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 its land base, manage financial resources, analyze seismic information, administer its contracts with its operators and lessees and communicate with employees and third-party operators.

Further, the Corporation is subject to a variety of information technology and system risks as a part of its normal course 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 its business activities or its 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.

Despite the Corporation's efforts to mitigate such cyber-phishing attacks through education and training, phishing activities remain a serious problem that may damage our 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 reputation, performance and earnings, which negative effect could prove to be material over time, 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, results of operations and prospects.

### **Social Media**

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.

### **Limited Ability of Residents in the United States to Enforce Civil Remedies**

The Corporation is a corporation formed under the laws of Alberta, Canada and has its principal place of business in Canada. All of our directors, except for Robert Leach, and all of our officers and the representatives of the experts who provide services to us (such as our auditors and our independent reserve engineers), and all of our assets and all or a substantial portion of the assets of such persons are located outside the United States. As a result, it may be difficult for investors in the United States to effect service of process within the United States upon such directors, officers and representatives of experts who are not residents of the United States or to enforce against them judgments of the United States courts based upon civil liability under the United States federal securities laws or the securities laws of any state within the United States. There is doubt as to the enforceability in Canada against the Corporation or against any of our directors, officers or representatives of experts who are not residents of the United States, in original actions or in actions for enforcement of judgments of United States courts of liabilities based solely upon the United States federal securities laws or securities laws of any state within the United States.

### **Negative Impact of Additional Sales or Issuances of Common Shares**

The Board may issue an unlimited number of Common Shares without any vote or action by the shareholders, subject to the rules of any stock exchange on which the Corporation's securities may be listed from time to time. The Corporation may make future acquisitions or enter into financings or other transactions involving the issuance of securities. If the Corporation issues any additional equity, the percentage ownership of existing shareholders will be reduced and diluted and the price of the Common Shares could decline.

## **Forward-Looking Information**

Shareholders and prospective investors are cautioned not to place undue reliance on Surge's forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Additional information on the risks, assumption and uncertainties are found under the heading "*Special Note Regarding Forward Looking Statements*" of this Annual Information Form.

## **MATERIAL CONTRACTS**

Except for those contracts listed below and contracts entered into in the ordinary course of business, the Company did not enter into any material contracts within the most recently completed financial year, or before the most recently completed financial year but which are still in effect.

- Indenture;
- First Lien Credit Facility; and
- Second Lien Term Debt Facility.

## **LEGAL PROCEEDINGS AND REGULATORY ACTIONS**

There are no outstanding legal proceedings material to the Corporation to which the Corporation is a party or in respect of which any of its properties are subject, nor are there any such proceedings known to the Corporation to be contemplated.

During the year ended December 31, 2023, there were (i) no penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority; (ii) no other penalties or sanctions imposed by a court or regulatory body against the Corporation that it believes would likely be considered important to a reasonable investor in making an investment decision; and (iii) no settlement agreements entered into by the Corporation with a court relating to securities legislation or with a securities regulatory authority.

## **INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS**

Michael Bennett, the Corporate Secretary of the Corporation, is a partner of the national law firm McCarthy Tétrault LLP, which law firm renders legal services to the Corporation.

Except as disclosed above or as may be disclosed elsewhere in this AIF, none of the directors, executive officers or principal shareholders of the Corporation, and no associate or affiliate of any of them, has or has had any material interest in any transaction or any proposed transaction which has materially affected or is reasonably expected to materially affect the Corporation or any of its affiliates.

## **AUDITOR, TRANSFER AGENT AND REGISTRAR**

KPMG LLP are the auditors of the Corporation and have confirmed that they are independent with respect to the Corporation within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations.

The transfer agent and registrar for the Common Shares is Odyssey Transfer Agent & Trust Company at its principal offices in Calgary, Alberta and Toronto, Ontario.

#### **INTEREST OF EXPERTS**

The Reserves Report and certain reserves estimates contained in filings made by the Corporation under NI 51-102 during the year ended December 31, 2023 were prepared by Sproule. As at the date of this Annual Information Form, the directors, officers, employees and consultants of Sproule who participated in the preparation of the Reserves Report or such reserves estimates or who were in a position to directly influence the preparation or outcome of the preparation of the Reserves Report or such reserves estimates, as a group, owned, directly or indirectly, less than one percent of the outstanding Common Shares.

KPMG LLP are independent of the Corporation pursuant to the rules of professional conduct of the Institute of Chartered Accountants of Alberta.

#### **ADDITIONAL INFORMATION**

Additional information concerning the Corporation may be found under the Corporation's profile on SEDAR+ at [www.sedarplus.com](http://www.sedarplus.com). Additional information, including information concerning directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans, will be contained in the information circular of the Corporation for the annual general meeting of the holders of Common Shares scheduled to be held in 2024. Additional financial information is provided in the Corporation's comparative financial statements and management's discussion and analysis for the year ended December 31, 2023.

**SCHEDULE "A"**

**Form 51-101F2**

**Report on Reserves Data  
by Independent Qualified Reserves Evaluator or Auditor**

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

1. We have evaluated the Company's reserves data as at December 31, 2023. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2023, estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.
3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook"), maintained by the 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, 2023, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date	Location of Reserves (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited (M\$)	Evaluated (M\$)	Reviewed (M\$)	Total (M\$)
Sproule	December 31, 2023	Canada				
<b>Total</b>			<b>Nil</b>	<b>2,059,059</b>	<b>Nil</b>	<b>2,059,059</b>

6. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
7. We have no responsibility to update our report referred to in paragraph 5 for events and circumstances occurring after the effective date of our report, entitled "Evaluation of the P&NG Reserves of Surge Energy Inc. (As of December 31, 2023)".
8. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Sproule Associates Limited,  
Calgary, Alberta

“Original signed by Maria Herrera, P.Eng.”

---

Maria Herrera, P.Eng.

*Senior Petroleum Engineer*

**DATE:** Feb. 15, 2024      RM APEGA ID#: 90581

**Sproule Associates Limited**

**APEGA Permit Number 00417**

“Original signed by Gary R. Finnis, P.Eng.”

---

Gary R. Finnis, P.Eng.

*Senior Manager, Engineering*

**DATE:** Feb. 16, 2024      RM APEGA ID#: 62965



## SCHEDULE "B"

### FORM 51-101F3

#### Report of Management and Directors on Reserves Data and Other Information

*Terms to which a meaning is ascribed in National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities have the same meaning herein.*

Management of Surge Energy Inc. (the "**Corporation**") are 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, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2023, estimated using forecast prices and costs.

Sproule Associates Limited, an independent qualified reserves evaluator, has evaluated and reviewed the Corporation's reserves data. The report of the independent qualified reserves evaluator is presented in Schedule "A" to the Annual Information Form of the Corporation for the year ended December 31, 2023 (the "**AIF**").

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 the independent qualified reserves evaluator to report without reservation; and
- (c) reviewed the applicable reserves data with management and with Sproule Associates Limited.

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, incorporated into the AIF, containing reserves data and other oil and gas information;
- (b) the filing of Form 51-101F2, which is the report of the independent qualified reserves evaluators on the reserves data; and
- (c) the content and filing of this report.

***[Balance of Page Intentionally Left Blank.]***

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

*(signed) "Paul Colborne"*

\_\_\_\_\_  
Paul Colborne, President & Chief Executive Officer

*(signed) "Jared Ducs"*

\_\_\_\_\_  
Jared Ducs, Chief Financial Officer

*(signed) "P. Daniel O'Neil"*

\_\_\_\_\_  
P. Daniel O'Neil, Director & Chair of the Reserves  
Committee

*(signed) "Daryl Gilbert"*

\_\_\_\_\_  
Daryl Gilbert, Director

March 6, 2024

## SCHEDULE "C"

### Audit Committee Charter



## AUDIT COMMITTEE CHARTER

### *Role and Objective*

The Audit Committee is a committee of the Board of Directors of Surge Energy Inc. (the "**Corporation**") to which the Board has delegated its responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for Board approval, the audited consolidated financial statements and other mandatory disclosure releases containing financial information of the Corporation. The objectives of the Audit Committee are as follows:

1. to assist directors in fulfilling their legal and fiduciary obligations (especially for accountability) in respect of the preparation and disclosure of the financial statements of the Corporation and related matters;
2. to oversee the audit efforts of the external auditors of the Corporation;
3. to maintain free and open means of communication among the directors, the external auditors, the financial and senior management of the Corporation;
4. to satisfy itself that the external auditors are independent of the Corporation; and
5. to strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors.

The function of the Committee is one of oversight of management and the external auditors in the execution of their responsibilities. Management is responsible for the preparation, presentation and integrity of the financial statements of the Corporation, maintaining appropriate accounting and financial reporting principles and policies and implementing appropriate internal controls and procedures. The external auditors are responsible for planning and carrying out a proper audit of the annual financial statements of the Corporation and reviewing the interim financial statements of the Corporation prior to their filing with securities regulatory authorities and other procedures.

### *Composition of the Committee*

1. The Audit Committee shall consist of at least three directors. The Board shall appoint one member of the Audit Committee to be the Chair of the Audit Committee.
2. Each director appointed to the Audit Committee by the Board must be independent. A director is independent if the director has no direct or indirect material relationship with the Corporation. A material relationship means a relationship which could, in the view of the Board, reasonably interfere with the exercise of the director's independent judgment. In determining whether a director is independent of management, the Board shall make reference to National Instrument 52-110 – Audit Committees or the then current legislation, rules, policies and instruments of applicable regulatory authorities.

3. Each member of the Audit Committee shall be "financially literate". In order to be financially literate, a director must be, at a minimum, able to read and understand financial statements that present a breadth and complexity of accounting issues generally comparable to the breadth and complexity of issues expected to be raised by the Corporation's financial statements.
4. A director appointed by the Board to the Audit Committee shall be a member of the Audit Committee until replaced by the Board or until his or her resignation.

### ***Meetings of the Committee***

1. The Audit Committee shall convene a minimum of four times each year at such times and places as may be designated by the Chair of the Audit Committee and whenever a meeting is requested by the Board, a member of the Audit Committee, the auditors, or a senior officer of the Corporation. Meetings of the Audit Committee shall correspond with the review of the interim financial statements and management discussion and analysis of the Corporation.
2. Notice of each meeting of the Audit Committee shall be given to each member of the Audit Committee. The auditors shall be given notice of each meeting of the Audit Committee at which financial statements of the Corporation are to be considered and such other meetings as determined by the Chair and shall be entitled to attend each such meeting of the Audit Committee.
3. Notice of a meeting of the Audit Committee shall:
  - (a) be in writing;
  - (b) state the nature of the business to be transacted at the meeting in reasonable detail;
  - (c) to the extent practicable, be accompanied by copies of documentation to be considered at the meeting; and
  - (d) be given at least two business days prior to the time stipulated for the meeting or such shorter period as the members of the Audit Committee may permit.
4. A quorum for the transaction of business at a meeting of the Audit Committee shall consist of a majority of the members of the Audit Committee. However, it shall be the practice of the Audit Committee to require review, and, if necessary, approval of certain important matters by all members of the Audit Committee.
5. A member or members of the Audit Committee may participate in a meeting of the Audit Committee by means of such telephonic, electronic or other communication facilities, as permits all persons participating in the meeting to communicate adequately with each other. A member participating in such a meeting by any such means is deemed to be present at the meeting.
6. In the absence of the Chair of the Audit Committee, the members of the Audit Committee shall choose one of the members present to be Chair of the meeting. In addition, the members of the Audit Committee shall choose one of the persons present to be the Secretary of the meeting.
7. The Chairman of the Board, senior management of the Corporation and other parties may attend meetings of the Audit Committee; however the Audit Committee (i) shall meet with the external auditors independent of management as necessary, in the sole discretion of the Committee, but in any event, not less than quarterly; and (ii) may meet separately with management.
8. Minutes shall be kept of all meetings of the Audit Committee and shall be signed by the Chair and the Secretary of the meeting.

### ***Duties and Responsibilities of the Committee***

1. It is the responsibility of the Audit Committee to oversee the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting. The external auditors shall report directly to the Audit Committee.
2. The Audit Committee shall, in the exercise of its powers, authorities and discretion so authorized, conform to any regulations or restrictions that may from time to time be made or imposed upon it by the Board or the legislation, policies or regulations governing the Corporation and its business.
3. It is the responsibility of the Audit Committee to satisfy itself on behalf of the Board that the Corporation's system of internal controls over financial reporting and disclosure controls and procedures are satisfactory for the purpose of:

- (a) identifying, monitoring and mitigating the principal risks;
- (b) ensuring compliance with legal, ethical and regulatory requirements;

and to review with the external auditors their assessment of the internal controls over financial reporting and the disclosure controls of the Corporation, their written reports containing recommendations for improvement, and management's response and any follow-up to any identified weaknesses.

4. It is the responsibility of the Audit Committee to review the annual financial statements of the Corporation and, if deemed appropriate, recommend the financial statements to the Board for approval. This process should include but be not to be limited to:

- (a) reviewing and accepting, if appropriate, the annual audit plan of the external auditors of the Corporation, including the scope of audit activities, and monitor such plan's progress and results during the year;
- (b) reviewing changes in accounting principles, or in their application, which may have a material impact on the current or future years' financial statements;
- (c) reviewing significant accruals, reserves or other estimates such as any impairment calculation;
- (d) reviewing the methods used to account for significant unusual or non-recurring transactions;
- (e) ascertaining compliance with covenants under loan agreements;
- (f) reviewing disclosure requirements for commitments and contingencies;
- (g) reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
- (h) reviewing unresolved differences between management and the external auditors;
- (i) obtain explanations of significant variances with comparative reporting periods;
- (j) review of business systems changes and implications;
- (k) review of authority and approval limits;
- (l) review the adequacy and effectiveness of the accounting and internal control policies of the Corporation and procedures through inquiry and discussions with the external auditors and management;

- (m) confirm through private discussion with the external auditors and the management that no management restrictions are being placed on the scope of the external auditors' work;
  - (n) review of tax policy issues;
  - (o) review of emerging accounting issues that could have an impact on the Corporation; and
  - (p) understand bias in decision-making and areas where significant judgment is applied.
5. It is the responsibility Audit Committee to review the interim financial statements of the Corporation and, if deemed appropriate, to recommend the financial statements to the Board for approval and to review all related management discussion and analysis. The Audit Committee must be satisfied that adequate procedures are in place for the review of the Corporation's disclosure of all other financial information and shall periodically assess the accuracy of those procedures.
6. The Audit Committee shall have the authority to:
- (a) inspect any and all of the books and records of the Corporation, its subsidiaries and affiliates;
  - (b) discuss with the management and senior staff of the Corporation, its subsidiaries and affiliates, any affected party and the external auditors, such accounts, records and other matters as any member of the Audit Committee considers necessary and appropriate;
  - (c) engage independent counsel and other advisors as it determines necessary to carry out its duties; and
  - (d) to set and pay the compensation for any advisors employed by the Audit Committee.
7. With respect to the appointment of external auditors by the Board, the Audit Committee shall:
- (a) recommend to the Board the appointment of the external auditors;
  - (b) review the performance of the external auditors and make recommendations to the Board regarding the replacement or termination of the external auditors when circumstances warrant;
  - (c) oversee the independence of the external auditors by, among other things, requiring the external auditors to deliver to the Audit Committee, on a periodic basis, a formal written statement delineating all relationships between the external auditors and the Corporation and its subsidiaries;
  - (d) 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 shall report directly to the Committee; and
  - (e) 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.
8. Audit Committee shall review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of the Corporation and its subsidiaries.

9. The Audit Committee must pre-approve all non-audit services to be provided to the Corporation or its subsidiaries by external auditors. The Audit Committee may delegate, to one or more members, the authority to pre-approve non-audit services, provided that the member report to the Audit Committee at the next scheduled meeting and such pre-approval and the member comply with such other procedures as may be established by the Audit Committee from time to time.
10. The Audit Committee shall review the Enterprise Risk Management framework and procedures of the Corporation (i.e. hedging, litigation and insurance), including the annual review of insurance coverage and make appropriate recommendations to the Board with respect thereto.
11. The Audit Committee shall receive regular updates with respect to information technology matters, including with respect to the Corporation's cyber security programs to address potential cyber-related risks.
12. The Audit Committee shall establish and maintain procedures for:
  - (a) the receipt, retention and treatment of complaints received by the Corporation regarding accounting controls, or auditing matters; and
  - (b) the confidential, anonymous submission by employees of the Corporation of concerns in accordance with the Corporation's Whistleblower Policy.
13. The Audit Committee shall review and approve the Corporation's hiring policies regarding employees and former employees of the present and former external auditors or auditing matters.
14. The Chairman of the Audit Committee shall review and approve the expenses incurred by the President and Chief Executive Officer.
15. The Audit Committee shall periodically report the results of reviews undertaken and any associated recommendations to the Board.
16. The Audit Committee shall assess, on an annual basis, the adequacy of this Mandate and the performance of the Audit Committee.