HEADWATER EXPLORATION INC.

ANNUAL INFORMATION FORM

Year Ended December 31, 2019

Dated March 25, 2020

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ABBREVIATIONS AND CONVERSIONS

Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
MBbls	thousand barrels
MMBbls	million barrels
Mstb	1,000 stock tank barrels
Bbls/d	barrels per day
BOPD	barrels of oil per day
NGLs	natural gas liquids
STB	standard tank barrels

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
MMbtu	million British Thermal Units
Bcf	billion cubic feet
GJ	gigajoule
MM	Million

Other

AECO	A natural gas storage facility located at Suffield, Alberta
AGT	Algonquin City-Gate natural gas pricing point on the Algonquin gas pipeline system
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale.
BOE	barrel of oil equivalent of natural gas and crude oil on the basis of 1 BOE for 6 Mcf of natural gas
BOE/d	barrel of oil equivalent per day
m3	cubic metres
MBOE	1,000 barrels of oil equivalent
MMBOE	1,000,000 barrels of oil equivalent
Mcfc	Thousand of cubic feet equivalent
$000s	thousands of dollars
$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

Disclosure provided herein in respect of BOEs of Mcfcs may be misleading, particularly if used in isolation. A BOE and Mcfc conversion ratio of 6 Mcf:1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion ratio at 6:1 may be misleading as an indication of value.

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
Bbls	cubic metres	0.159
cubic metres	Bbls oil	6.290
feet	meters	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres (Alberta)	hectares	0.400
hectares (Alberta)	acres	2.500

NOTES ON RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Caution Respecting Reserves Information

The determination of oil, NGLs 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 recovery and reserve estimates of oil, NGLs 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 Headwater's anticipated oil, NGLs and natural gas reserves does not represent the fair market value of Headwater's proposed reserves.

Oil and Gas Metrics

This Annual Information Form contains certain oil and gas metrics, including "future development costs" which do not have standardized meanings or standard methods of calculation and therefore such metrics may not be comparable to similar metrics used by other companies. Such metrics have been included herein to provide readers with additional measures to evaluate the Corporation's performance; however, such measures are not reliable indicators of the future performance of the Corporation and future performance may not compare to the performance in previous periods. Management uses these oil and gas metrics for its own performance measurements and to provide securityholders with measures to compare Headwater's operations over time. Future development costs are calculated as the sum of development capital plus the change in future development costs for the period. Future development costs, are not recognized measures under IFRS and do not have a standardized meanings. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented herein, should not be relied upon for investment or other purposes.

Oil and Gas Definitions

Certain terms used in this Annual Information Form in describing reserves and other oil and natural gas information are defined below. Certain other terms and abbreviations used in this Annual Information Form, but not defined or described, are defined in National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**") or the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**") and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 or the COGE Handbook.

"**API**" means the American Petroleum Institute;

"**API gravity**" means the American Petroleum Institute gravity expressed in degrees in relation to liquids, which is a measure of how heavy or light a petroleum liquid is compared to water. If a petroleum liquid's API gravity is greater than 10, it is lighter and floats on water; if less than 10, it is heavier than water and sinks. API gravity is thus a measure of the relative density of a petroleum liquid and the density of water, but it is used to compare the relative densities of petroleum liquids;

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

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

"**development well**" means a well drilled inside the established limits of an oil or 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 exploration wells and exploration 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: (a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as "geological and geophysical costs"); (b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records; (c) dry hole contributions and bottom hole contributions; (d) costs of drilling and equipping exploration wells; and (e) costs of drilling exploration type stratigraphic test wells;

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

"**forecast prices and costs**" means future prices and costs that are:

(a) generally accepted as being a reasonable outlook of the future; or

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which Headwater is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in subparagraph (a);

"**gross**" means: (a) 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; (b) in relation to wells, the total number of wells in which an issuer has an interest; and (c) in relation to properties, the total area of properties in which an issuer has an interest;

"**net**" means: (a) 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; (b) 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 (c) 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;

"**NGLs**" means natural gas liquids;

"**P+P Reserves**" means Proved Reserves plus Probable 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 P+P Reserves;

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

"**Reserves Data**" has the meaning set forth under the heading "*Statement of Reserves Data and other Oil and Gas Information*" in this Annual Information Form;

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

"**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 subdivide 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; and

"**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.

Levels of Certainty for Reported Reserves

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

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated Proved Reserves; and

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the estimated P+P Reserves.

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

NON-IFRS MEASURES

In the Annual Information Form, the Corporation uses the terms "netback" and "free cash flow". These measures are not recognized by International Financial Reporting Standards ("**IFRS**") and do not have standardized meanings prescribed by IFRS. Therefore, it may not be comparable to performance measures presented by others. The Corporation calculates netback on a boe basis as sales less realized gains and losses on financial derivatives, less royalties, production and transportation expenses. Netback is utilized by the Company to assess the profitability of the Company's liquids and natural gas sales and is a common metric used in the oil and gas industry. It is used by management to measure operating results on a per boe basis to better analyze performance against prior periods on a comparable basis. Free cash flow is calculated as cash flow from operations, adjusted for non-cash working capital less capital expenditures. Free cash flow is used by the Company to determine the amount of cash that is available to return to the shareholders or the business.

CERTAIN DEFINITIONS

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

"**ABCA**" means the *Business Corporations Act* (Alberta), as amended, including any regulations promulgated thereunder

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

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

"**Corporation**" or "**Headwater**" means Headwater Exploration Inc., a corporation existing under the ABCA;

"**GLJ**" means GLJ Petroleum Consultants Ltd.;

"**GLJ Report**" means the independent reserves assessment prepared by GLJ dated February 27, 2020 evaluating the gas property of the Corporation as at December 31, 2019;

"**Initial Investors**" means, collectively, Neil Roszell, Jason Jaskela, Ali Horvath, Jonathan Grimwood and Terry Danku;

"**Investment Agreement**" means the amended and restated investment agreement entered into by the Corporation and the Initial Investors on January 15, 2020;

"**M&NP**" means the Maritimes & Northeast Pipeline;

"**New Management Team**" means the current officers of the Corporation who were appointed on March 4, 2020 and consist of: Neil Roszell as Chairman and Chief Executive Officer, Jason Jaskela as President and Chief Operating Officer, Ali Horvath as Vice President, Finance and Chief Financial Officer, Jonathan Grimwood as Vice President, Exploration, Terry Danku as Vice President, Engineering, Scott Rideout as Vice President, Land and Edward (Ted) Brown as Corporate Secretary;

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

"**OPEC+**" means the Organization of the Petroleum Exporting Countries and certain additional plus countries;

"**Private Placements**" means together, the Subscription Receipt Private Placement and the Unit Private Placement;

"**Reconstitution of Management**" means, concurrently with the Unit Private Placement: (i) the resignation and appointment of directors in accordance with the Investment Agreement, such that following the reconstitution, the members of the Board were as follows: Chandra Henry, Martin Fräss-Ehrfeld, Jason Jaskela, Phillip Knoll, Stephen Larke, Kevin D. Olson, David Pearce and Neil Roszell; and (ii) the resignation and appointment of officers of the Corporation in accordance with the Investment Agreement, such that following the reconstitution, the officers of the Corporation are the New Management Team;

"**Repsol**" means Repsol Oil & Gas Canada Inc.;

"**Shareholders**" means holders of Common Shares;

"**Subscription Receipt Agreement**" means the subscription receipt agreement dated February 11, 2020 between the Corporation, Stifel Nicolaus Canada Inc., National Bank Financial Inc. (on their own behalf and on behalf of Peters & Co. Limited) and Computershare Trust Company of Canada;

"**Subscription Receipt Private Placement**" means the brokered private placement of 32,608,696 Subscription Receipts at a price of $0.92 per Subscription Receipt for gross aggregate proceeds of approximately $30 million completed on February 11, 2020 as part of the Private Placements and Reconstitution of Management;

"**Subscription Receipts**" means the subscription receipts of the Corporation issued pursuant to the Subscription Receipt Private Placement, with each subscription receipt entitling the holder thereof to receive, without payment of additional consideration or further action on the part of such holder, one (1) Common Share upon the satisfaction of certain conditions, including that all conditions, undertakings and other matters to be satisfied, completed or otherwise met prior to the completion of the Unit Private Placement and Reconstitution of Management (in accordance with the Investment Agreement) without waiver or material amendment thereof, have been satisfied, completed or otherwise met;

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

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

"**Unit**" means a unit of the Corporation comprised of one (1) Common Share and one (1) Warrant;

"**Unit Private Placement**" means the private placement of 21,739,130 Units of the Corporation at a price of $0.92 per Unit for gross aggregate proceeds of approximately $20.0 million completed on March 4, 2020 as part of the Private Placements and Management Reconstitution; and

"**Warrants**" means the common share purchase warrants issued under the Unit Private Placement, each Warrant entitling the holder to purchase one Common Share at a price of $0.92 per Common Share for a period of four (4) years from the issuance date and which vest and become exercisable as to one-third upon the 20 day volume weighted average price of the Common Shares equaling or exceeding each of $1.30, $1.60 and $1.90 per Common Share, respectively.

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

Unless otherwise specified, information in this Annual Information Form is as at the end of the Corporation's most recently completed financial year, being December 31, 2019.

Words importing the singular number only include the plural, and vice versa, and words importing any gender include all genders.

All dollar amounts herein are in Canadian dollars, unless otherwise stated.

FORWARD-LOOKING STATEMENTS

The information herein contains forward-looking statements or forward-looking information (collectively, "**forward-looking statements**") within the meaning of applicable Canadian securities laws. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict, "potential", "targeting", "intend", "could", "might, "should", "believe", "would" and similar expressions. Such statements and assumptions also include those relating to: the intent to maintain a strong balance sheet with sufficient liquidity; the Corporation's working capital balance as at March 31, 2020 and expected field based cashflow; the Corporation's position with respect to potential acquisition opportunities, including a focus in the western Canadian sedimentary basin; the expectation that acquisitions will focus on asset quality, balance sheet strength and investor returns; the Corporation's ability to engage in Indigenous consultation and pursue an exemption to the fracking moratorium in

New Brunswick in order to allow the Corporation to continue the development of the McCully Field; the focus of the Corporation's 2020 capital expenditure program; development plans for the assets of the Corporation; land expiries; abandonment and reclamation costs; the performance characteristics of oil and natural gas properties; the quantity of reserves; natural gas production levels; drilling plans; projected amount of capital expenditures, capital expenditure programs and the timing thereof; the tax horizon of Headwater; supply and demand for oil and natural gas; expectations regarding Headwater's ability to raise capital and to continually add to reserves through acquisitions and development; and treatment under government regulatory and taxation regimes. Statements relating to "reserves" 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.

Forward-looking statements are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although Headwater believes that the expectations reflected in such forward-looking statements are reasonable, undue reliance should not be placed on forward-looking statements because Headwater can give no assurance that such expectations will prove to be correct.

In addition to other factors and assumptions which may be identified in this document, assumptions have been made regarding, among other things: that the Corporation will be able to capitalize on potential asset consolidations and/or other acquisition opportunities in the current economic environment; that royalty regimes will not be subject to material modification; that the Corporation will be able to obtain skilled labour and other industry services at reasonable rates; that the timing and amount of capital expenditures and implementation thereof will be consistent with the Corporation's expectations; that the conditions in general economic and financial markets will not continue to vary materially; that drilling and other equipment will be available on acceptable terms; that government regulations and laws will not change materially; that future operating costs will be consistent with the Corporation's expectations; the impact of increasing competition; the general stability of the economic and political environment in which Headwater operates; the timely receipt of any required regulatory approvals; the ability of Headwater to obtain qualified staff, equipment and services in a timely manner; future drilling results; the ability of Headwater to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development of exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of Headwater to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which Headwater operates; and the ability of Headwater to successfully market its oil and natural gas products.

A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements including, but not limited to, risks associated with public health risks including the 2019 novel coronavirus ("**COVID-19**"), risks associated with volatility of commodity prices and stock exchanges, oil and natural gas exploration, development, exploitation, production, changes to the Corporation's capital budget, marketing and transportation, loss of markets, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, ability to access sufficient capital from internal and external sources and the risk factors outlined under "*Risk Factors*" and elsewhere herein. Operations may be unsuccessful or delayed as a result of the province-wide fracking moratorium in New Brunswick, competition for services, supplies and equipment, mechanical and technical difficulties, challenges associated with attracting and retaining employees on a cost-effective basis, and commodity and marketing risks. The Corporation is subject to significant drilling risks and uncertainties relating to its ability to find oil and natural gas reserves on an economic basis and the potential for technical problems that could lead to well blowouts and environmental damage. The Corporation is also exposed to risks relating to obtaining timely regulatory approvals, surface access, transportation and other third party related operational risks. Furthermore, there are numerous uncertainties in estimating the Corporation's reserve base due to the complexities in estimated future production, costs and timing of expenses and future capital. The Corporation is subject to regulatory legislation, which may require significant expenditures to ensure compliance or which may result in fines, penalties or production restrictions for non-compliance.

The forward-looking statements contained herein are as of March 25, 2020 and are subject to change after this date. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Except as required by law, Headwater disclaims any intention or obligation to update or revise these forward-looking statements, whether as a result of new information, future events or otherwise.

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. For a full description of the risk factors, please see "Risk Factors" in this Annual Information Form.

THE CORPORATION

General

Headwater is the corporation resulting from the amalgamation under the ABCA on May 13, 1996 of "Corridor Resources Inc." and Contwoyto Goldfields Limited. On June 14, 2011, the articles of the Corporation were amended to increase the minimum and maximum number of directors of the Corporation to three directors and nine directors, respectively. On March 4, 2020, in connection with the Private Placements and the Reconstitution of Management, the Corporation filed Articles of Amendment to change its name from "Corridor Resources Inc." to "Headwater Exploration Inc." The Corporation has no material subsidiaries.

The head office of Headwater is located at 1700, 500 – 4th Avenue S.W., Calgary, Alberta T2P 2V6 and its registered office is located at 2400, 525 – 8th Avenue S.W., Calgary, Alberta T2P 1G1.

The Common Shares trade on the TSX under the symbol "HWX".

GENERAL DEVELOPMENT OF THE BUSINESS

The following is a summary description of the development of Headwater's business during the last three completed financial years.

Recent Developments

Private Placements and Reconstitution of Management

On January 12, 2020, the Corporation entered into an initial investment agreement (the "**Initial Investment Agreement**") with the Initial Investors which provided for: (i) the Unit Private Placement; (ii) a brokered private placement of Common Shares for gross proceeds of a minimum of $20.0 million and a maximum of $30.0 million (the "**Brokered Share Private Placement**"); and (iii) the Reconstitution of Management. On January 15, 2020, in light of the TSX requiring the Corporation obtain approval of an ordinary resolution in respect of the Unit Private Placement at a special meeting ("**Special Meeting**") of the Shareholders (the "**Unit Private Placement Resolution**"), the Corporation and the Initial Investors entered into the Investment Agreement to substitute the Subscription Receipt Private Placement for the Brokered Share Private Placement. On February 11, 2020, the Corporation completed the Subscription Receipt Private Placement.

On March 4, 2020, the Corporation held the Special Meeting and the Unit Private Placement Resolution as well as a special resolution to amend the articles of the Corporation to change its name from "Corridor Resources Inc." to "Headwater Exploration Inc." were approved.

Following the Special Meeting, the Unit Private Placement and Reconstitution of Management were completed and the Common Shares underlying the Subscription Receipts were issued in accordance with the terms of the Subscription Receipt Agreement. In addition, the Corporation filed Articles of Amendment to change its name to "Headwater Exploration Inc.".

For a complete description of the transactions contemplated by the Investment Agreement, reference should be made to the Investment Agreement and the material change report of the Corporation dated March 13, 2020, copies of which have been filed on SEDAR at www.sedar.com.

General Operations

Gulf of St. Lawrence

On January 14, 2020, further to the decision made by the Corporation in June 2018 to suspend any further technical work and capital spending on the Old Harry prospect, the Corporation's exploration license EL-1153 on the eastern end of the Old Harry prospect to explore 127,948 net acres of undeveloped land expired. Headwater plans to surrender approximately 123,550 net acres of undeveloped land in the Old Harry prospect in the Laurentian Channel in Québec.

Year 2019

Strategic Review Process

On October 31, 2019, the Corporation announced that the Board had approved the initiation of a strategic review process to explore and develop strategic alternatives with a view of enhancing Shareholder value. The process was intended to explore a comprehensive range of strategic transaction alternatives including: (i) opportunities to selectively deploy capital (within the resource sector or otherwise); (ii) a disposition of all or substantially all of the Corporation's assets; and (iii) a merger or other business combination. In connection with the strategic review process, the Corporation engaged RBC Dominion Securities Inc. as financial advisor to assist in undertaking the process.

McCully Field, New Brunswick

As part of its production optimization strategy, the Corporation shut-in its natural gas production in the McCully Field in New Brunswick in May 2019 and resumed production in November 2019.

Year 2018

General Operations

New Brunswick

In November 2018, the Government of New Brunswick expressed its intention to allow natural gas development in the Sussex region, where the Corporation's properties are located. On December 19, 2018, the Corporation announced that its future activities in respect of the Frederick Brook shale would be focused on initially attracting a joint venture partner to bring capital and shale gas expertise to assist with further evaluation of the Frederick Brook shale by way of a pilot project to be developed with such joint venture partner.

McCully Field, New Brunswick

As part of its production optimization strategy, the Corporation shut-in its natural gas production in the McCully Field in New Brunswick in May 2018 and resumed limited production in November 2018, with a ramp-up in production in December 2018. The Corporation sells all of its share of the natural gas produced from the McCully Field to Repsol pursuant to a long-term agreement. The Corporation's natural gas production has historically been sold in the New England market in the northeastern U.S. at prices referenced to AGT but has recently been expanded to include sales to local markets in the Maritimes given the decrease in natural gas production in Atlantic Canada. In 2018, the Corporation and Repsol amended their long-term agreement to eliminate transportation charges on the Canadian portion of the M&NP from November 1, 2018 to April 1, 2024 in recognition of the changing market.

Gulf of St. Lawrence

In June 2018, the Corporation concluded there was no longer a viable path to drilling an exploration well on the Old Harry prospect in the Gulf of St. Lawrence before the current exploration licence on the Newfoundland side expires in January 2021 and, accordingly, the Corporation determined to suspend any further technical work and capital spending on the Old Harry prospect.

Normal Course Issuer Bid

The Corporation implemented a normal course issuer bid (the "**NCIB**") under the TSX that commenced on August 23, 2018 and expired on August 22, 2019. Under the NCIB, the Corporation purchased 777,460 Common Shares.

Strategic Review Process

During 2018, the Corporation continued to evaluate opportunities with a disciplined approach to deploy surplus working capital. In this regard, the Board conducted a strategic review to identify and consider a broad range of potential opportunities with the objective of enhancing Shareholder value. While the Board evaluated a number of opportunities, it did not enter into any transaction given the assessment that such opportunities were not in the best interest of the Corporation. In June 2018, the Corporation suspended its strategic review process due to: (i) the lack of opportunities that satisfied the Board's objectives; and (ii) the possibility that the moratorium on hydraulic fracturing in New Brunswick may be lifted, and determined to focus on the further evaluation of the Frederick Brook shale as the scope and scale of the opportunity in the Frederick Brook shale represents a more significant upside potential for Shareholders.

Year 2017

General Operations

McCully Field, New Brunswick

From April 1, 2017 to November 30, 2017, the Corporation shut-in most of its natural gas production in accordance with its production optimization strategy. In 2017, the Corporation entered into a financial hedge for 2,500 MMbtu per day of natural gas production (approximately 2.3 MMcf per day) for the period from December 1, 2017 to March 31, 2018 at a fixed price of $US7.40/MMbtu and for 2,500 MMbtu/d of natural gas production for the period from December 1, 2017 to February 28, 2018 at a fixed price of $US7.83/MMbtu. The Corporation entered into forward sale agreements for the period from December 1, 2017 to March 31, 2018 to deliver natural gas to the local Maritimes market as opposed to the New England market.

Termination of the Corporation's Activities / Interests in Anticosti Hydrocarbons

In light of the Québec Government's decision in January 2017 to support the designation of Anticosti Island as a UNESCO World Heritage site and the resulting uncertainty that Anticosti Hydrocarbons' drilling program would proceed, the Corporation, together with other partners of Anticosti Hydrocarbons, entered into negotiations with the Government of Québec with the goal of terminating the exploration joint venture project on Anticosti Island, including the Anticosti Joint Venture.

On July 28, 2017, the Corporation announced that it had reached a settlement agreement with the Government of Québec that facilitated an end to its participation in oil and gas exploration on Anticosti Island, including the Anticosti Joint Venture. Under the settlement agreement, the Corporation agreed to cease all hydrocarbon exploration activities on Anticosti Island and the Québec Government paid the Corporation $19.5 million in consideration for, amongst other things, the prejudice suffered by the Corporation in connection with its interests in Anticosti Hydrocarbons. The Québec Government also agreed to reimburse the Corporation for any further amounts expended prior to its departure from Anticosti Island, and to assume all abandonment and reclamation obligations in respect of three Anticosti wells in which the Corporation has an interest outside of Anticosti Hydrocarbons.

Gulf of St. Lawrence

On January 15, 2017, the Corporation announced that the C-NLOPB issued exploration license EL-1153 to the Corporation in exchange for the surrender of exploration license EL-1105 covering the Old Harry prospect in the Gulf of St. Lawrence. The new exploration license expires on January 14, 2020, subject to extension by the Corporation for an additional one year period (January 14, 2021) with the payment of a $1 million deposit.

In November 2017, the Corporation conducted a CSEM survey over the Newfoundland and Labrador sector of the Old Harry prospect with the objective of investigating the resistivity of geological prospects, similar to resistivity logging in well bores of potential hydrocarbon zones. Highly resistive layers in a geological structure measured with CSEM technology could indicate hydrocarbon bearing reservoirs and, therefore, could serve to reduce exploration risk and increase the likelihood of finding commercial quantities of hydrocarbons.

In November 2017, an environmental based group filed an originating application challenging the C-NLOPB's issuance of exploration licence EL-1153 to the Corporation in January 2017 and seeking confirmation from the Supreme Court of Newfoundland and Labrador that any and all of the Corporation's exploration licences on the Newfoundland side of Old Harry have expired. The originating application to the Supreme Court of Newfoundland and Labrador claimed that the C-NLOPB "erred in law and acted unreasonably" when it issued the Corporation this license in exchange for the Corporation's then expiring exploration licence EL-1105 covering the Newfoundland and Labrador side of the Old Harry prospect. The C-NLOPB (i) filed an application objecting to the standing of the applicant on the basis that they are not persons aggrieved by the issuance of EL-1153 and they have no legal stake in the matter of the validity of EL-1153; and also (ii) filed an affidavit in opposition to the merits of the applicant's originating application. The Corporation supported the CNLOPB's position and was granted intervener status in the case, as was the Government of Newfoundland and Labrador.

Significant Acquisitions

Headwater did not complete any significant acquisitions during its most recently completed financial year for which disclosure is required under Part 8 of NI 51-102.

DESCRIPTION OF THE BUSINESS

The Corporation is a Canadian junior resource company currently engaged in the exploration for and development and production of petroleum and natural gas onshore in New Brunswick. The Corporation currently has natural gas production and reserves in the McCully Field near Sussex, New Brunswick. In addition, the Corporation has a shale gas prospect in New Brunswick. With the recent completion of the Private Placements and Reconstitution of Management, the New Management Team is focused on expanding its operations to included resource exploration and development in the western Canadian sedimentary basin.

Headwater's operations are currently focused on two principal properties, being the McCully Field, New Brunswick and the Frederick Brook shale prospect in the Elgin Sub-Basin, New Brunswick. Atlantic Canada remains undersupplied by regional gas by approximately 140 MMcf/d. The New Management Team believes this allows for unabated growth in McCully Field gas supply. In June 2019, the New Brunswick Government issued an order-in-council that permits the Minister of Energy & Resource Development to exempt the Corporation's McCully Field from the province-wide fracking moratorium. The New Management Team intends to engage in Indigenous consultation and pursue such exemption, allowing the Corporation to continue the development of the McCully Field.

Business Strategy

Headwater is in a position to consolidate assets in the Canadian energy sector with a forecasted positive working capital balance of approximately $115 million as at March 31, 2020, stable field based cashflow of $5-7 million per year in addition to a strong tax pool balance of approximately $159 million (as at December 31, 2019).

The rapid deterioration in crude oil prices from the simultaneous supply and demand shocks are providing a generational opportunity for well capitalized companies in the Canadian energy sector. The New Management Team continues to assess the unique opportunities that have been and continue to be created by the current market dynamics. The New Management Team's focus on asset quality, balance sheet strength and investor returns are anticipated to result in one or more strategic acquisitions in the western Canadian sedimentary basin that will be combined with organic development to obtain superior corporate level returns.

See "*Industry Conditions*" and "*Risk Factors*" for further details.

Specialized Skill and Knowledge

The Corporation relies on specialized skills and knowledge to gather, interpret and process geophysical data; drill and complete wells; design and operate production facilities; and for numerous additional activities required to explore for and produce oil and natural gas. The Corporation has employed a strategy of contracting consultants and other services providers to supplement the skills and knowledge of its permanent staff in order to provide the specialized skills and knowledge to undertake its oil and natural gas operation effectively. See "*Directors and Executive Officers of the Corporation*".

Reorganizations

There have been no material reorganizations of the Corporation in the last three completed financial years or proposed for the current financial year.

Personnel

As of December 31, 2019, the Corporation had 5 employees, 5 field employees and 1 full-time consultant.

Following the Private Placements and Reconstitution of Management, the Corporation had 6 employees in the head office, 3 employees in the Halifax office, 5 field employees and 1 full-time consultant.

Marketing

A key component of the Corporation's production optimization strategy is to enter into financial hedges to mitigate the risks associated with the volatility of natural gas prices during the winter heating season when natural gas is produced from the McCully Field.

The Corporation produces natural gas from the McCully Field in New Brunswick (the Corporation's only producing field), which is connected to the M&NP that supplies customers in the Maritimes and the New England market in the northeastern U.S. The New England market has in recent years been characterized by excess demand during the winter season resulting in elevated prices for natural gas as compared to prices in other areas of North America, and this excess demand is expected to continue until new pipeline infrastructure is available to increase the supply of natural gas into this market. While projects are planned which could alleviate supply constraints in the New England and Maritimes markets, it is not known whether the required regulatory approvals will be received and, if the projects proceed, the timing of completion of such projects. In addition, natural gas production from Sable Island and Deep Panuke in the Maritimes ended in 2018 resulting in excess demand and expected higher natural gas prices in the Maritimes.

The Corporation sells all its share of the natural gas produced from the McCully Field to Repsol pursuant to a long-term agreement which became effective on April 1, 2009 and will terminate on April 1, 2024. The Corporation's natural gas production has historically been sold in the New England market in the northeastern U.S. at prices referenced to AGT but has recently been expanded to include sales to local markets in the Maritimes given the decrease in natural gas production in Atlantic Canada. In 2018, the Corporation and Repsol amended their long-term agreement to eliminate transportation charges on the Canadian portion of the M&NP from November 1, 2018 to April 1, 2024 in recognition of the changing market.

The production, transportation, processing and marketing of natural gas from Nutrien's share of the production from the McCully Field are subject to agreements with Nutrien. Nutrien's share of natural gas production is either taken in kind for use at the Nutrien potash facility, located near Sussex, New Brunswick or delivered to the Corporation's midstream facilities for sale by Nutrien to the Maritimes market and New England market.

The Corporation has also adopted a hedging policy – see "*Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Forward Contracts*". For details of the Corporation's forward contracts in place as at December 31, 2019 see the Corporation's audited annual financial statements for the year ended

December 31, 2019, which have been filed on SEDAR and may be viewed under the Corporation's profile at www.sedar.com. See "*Risk Factors – Prices, Markets and Marketing*".

Cyclical and Seasonal Nature of Industry

Headwater's operational results and financial condition are dependent on the prices received for natural gas production. Natural gas prices have recently fluctuated widely and are determined by supply and demand factors. The energy business is cyclical in nature and heavily influenced on macro-economic cycles and other factors affecting supply and demand. In periods of economic expansion and growth the demand for energy increases as economies build inventory and productive capacity. Generally speaking in periods of economic contraction or recession, demand for energy declines. These macroeconomic cycles often impact global, North American and local prices for commodities, particularly oil and gas prices. Weather and general economic conditions also impact supply and demand of commodity prices and costs. Any decline in natural gas prices could have an adverse effect on Headwater's financial condition. Headwater mitigates such price risk through closely monitoring the various commodity markets and establishing hedging programs, as deemed necessary, to lock-in high netbacks on production volumes.

See "*Risk Factors – Weakness and Volatility in the Oil and Natural Gas Industry*", "*Risk Factors – Seasonality*" and "*Risk Factors – Acute Climate Change Risk*".

Environmental Considerations and Protection

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

Headwater believes in well abandonment and site restoration in a timely manner to ensure minimal damage to the environment and lower overall costs. As a result, Headwater will allocate a portion of its annual capital budget to such activities.

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

Although Headwater operates in compliance with all applicable regulations and ensures that all staff and contractors employ sound practices to protect the environment and to ensure employee and public health and safety, occasionally fluid spills and other incidents threatening the environment may occur. The costs of cleaning up such spills could negatively affect the Corporation's financial and operating results as the Corporation has to incur costs and utilize resources in cleaning up such spills. In 2019, the Corporation did not have any material spills or releases.

Health, Safety, Environmental and Social Policies

In addition to the Board's oversight of Headwater's environmental and safety practices, management, employees and all contractors will be responsible and accountable for the overall health, safety and environmental program. Headwater 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.

Headwater 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.

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

The Corporation also has an Emergency Response Plan (the "**ERP**") which is prepared in accordance with applicable regulations. The ERP is designed to provide the policies, practices and procedures to be implemented in the event of an emergency situation that arises at or as a result of Headwater's operations, including but not limited to: a serious injury or fatality, fire or explosion, uncontrolled or hazardous product release and oil or hazardous chemical spill. The purpose of the ERP is to protect the health, safety and welfare of the public and workers and minimize the potential adverse environmental effects. Management intends to test the ERP in 2020 to ensure its effectiveness and its procedures are revised to ensure the Corporation is adhering to the highest industry standards.

The Board also receives periodic updates from management on implemented or proposed legislative or regulatory changes that may affect the Corporation's operations. Periodically, the Board discusses and reviews Headwater's environmental, health and safety policies and, with management input, makes suggestions to ensure that the Corporation is adhering to best practices within the industry.

Competitive Conditions

Headwater is a member of the petroleum industry, which is highly competitive at all levels. Headwater competes with other companies for all of its business inputs, including exploitation and development prospects, access to commodity markets, acquisition opportunities, available capital and staffing. See "*Risk Factors – Competition*".

Headwater strives to be competitive by maintaining a strong financial condition and by utilizing current technologies to enhance exploitation, development and operational activities.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "**Reserves Data**") is dated March 25, 2020. The effective date of the Reserves Data is December 31, 2019 and the preparation date of the Reserves Data is February 27, 2020.

Disclosure of Reserves Data

The Reserves Data set forth below is based upon the evaluation by GLJ with an effective date of December 31, 2019 contained in the Reserve Report. The Reserves Data summarizes the NGLs, natural gas and shale gas reserves associated with the Corporation's assets and the net present values of future net revenue for such reserves using forecast prices and costs. The tables below are a combined summary of the Corporation's NGLs, natural gas and shale gas reserves and the net present value of future net revenue attributable to such reserves as evaluated in the Reserve Report based on GLJ's December 31, 2019 forecast price and cost assumptions. The NGLs, natural gas and shale gas reserve estimates presented in the Reserve Report are based on the guidelines contained in the COGE Handbook and the reserve definitions contained in both NI 51-101 and the COGE Handbook. A summary of those definitions are set forth in the glossary to this Annual Information Form. GLJ was engaged to provide evaluations of Proved Reserves and P+P Reserves and no attempt was made to evaluate possible reserves. Additional information not required by NI 51-101 has been presented to provide continuity and additional information, which Headwater believes is important to the readers of this information.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There are numerous uncertainties inherent in estimating quantities of NGLs, natural gas and shale gas reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this Annual Information Form are estimates only. The recovery and reserve estimates of the NGLs, natural gas and shale gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual NGLs, natural gas and shale gas reserves may be greater than or less than the estimates provided herein. In general, estimates of economically recoverable NGLs, natural gas and shale gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of NGLs, natural gas and shale gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, among others, estimates of the economically recoverable NGLs, natural gas and shale gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves may vary and such variations may be material. The actual production, revenues, taxes and development and operating expenditures with respect to the reserves associated with the Corporation's assets may vary from the information presented herein and such variations could be material.

In accordance with the requirements of NI 51-101, the Report on Reserves Data by Independent Qualified Reserves Evaluator in Form 51-101F2 and the Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 are attached as Appendices "A" and "B" hereto, respectively.

All of Headwater's reserves are located in the McCully Field in New Brunswick, Canada. There are no reserves assigned to the Frederick Brook shale in the Elgin Sub-Basin. Please note that rounding errors may occur in the tables set forth below in this Statement of Reserves Data and Other Oil and Gas Information.

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
as of December 31, 2019
FORECAST PRICES AND COSTS

Reserve Category[(1)]	Conventional Natural Gas[(2)]		Shale Natural Gas[(2)]		Natural Gas Liquids[(2)]		Total Oil Equivalent[(2)]	
	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf))	Gross (MBbl)	Net (MBbl)	Gross (MBoe)	Net (MBoe)
PROVED[(3)]								
Developed Producing	17,163	16,796	836	818	18	18	3,018	2,953
Undeveloped[(4)]	-	-	-	-	-	-	-	-
TOTAL PROVED	17,163	16,796	836	818	18	18	3,018	2,953
PROBABLE								
Developed Producing	3,921	3,837	197	193	4	4	691	676
Undeveloped[(4)]	-	-	-	-	-	-	-	-
TOTAL PROBABLE	3,921	3,837	197	193	4	4	691	676
TOTAL PROVED PLUS PROBABLE	**21,084**	**20,633**	**1,034**	**1,011**	**22**	**22**	**3,709**	**3,629**

Notes:

(1) All of the Corporation's reserves are currently producing.
(2) Columns may not add due to rounding.
(3) The GLJ Reserves Report does not include any developed non-producing reserves.
(4) The GLJ Reserves Report does not include any undeveloped reserves.

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE[(4)]
as at December 31, 2019
FORECAST PRICES AND COSTS

	Before Income Tax Discounted at (%/year)					After Income Taxes Discounted at (%/year)					Before Tax Net Value
RESERVES CATEGORY[(1)]	**0 ($000s)**	**5 ($000s)**	**10 ($000s)**	**15 ($000s)**	**20 ($000s)**	**0 ($000s)**	**5 ($000s)**	**10 ($000s)**	**15 ($000s)**	**20 ($000s)**	**10%/yr ($/BOE)[(2)]**
PROVED[(3)(4)]											
Developed Producing	64,875	55,610	46,706	39,686	34,352	64,875	55,610	46,706	39,686	34,352	15.81
Undeveloped	-	-	-	-	-	-	-	-	-	-	-
TOTAL PROVED	64,875	55,610	46,706	39,686	34,352	64,875	55,610	46,706	39,686	34,352	15.81
PROBABLE[(3)(4)]											
Developed Producing	23,050	14,248	8,883	5,845	4,079	23,050	14,248	8,883	5,845	4,079	13.15
Undeveloped	-	-	-	-	-	-	-	-	-	-	-
TOTAL PROBABLE	23,050	14,248	8,883	5,845	4,079	23,050	14,248	8,883	5,845	4,079	13.15
TOTAL PROVED PLUS PROBABLE	**87,925**	**69,858**	**55,589**	**45,532**	**38,431**	**87,925**	**69,858**	**55,589**	**45,532**	**38,431**	15.32

Notes:

(1) All of the Corporation's reserves are currently producing.
(2) The unit values are based on net reserve volumes.
(3) The GLJ Reserves Report does not include any developed non-producing reserves.
(4) The GLJ Reserves Report does not include any undeveloped reserves.
(5) The estimated values of future net revenues disclosed do not represent fair market value.

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as at December 31, 2019
FORECAST PRICES AND COSTS[(1)]

RESERVES CATEGORY	REVENUE ($000s)	ROYALTIES ($000s)	OPERATING COSTS ($000s)	DEVELOP-MENT COSTS ($000s)	ABANDONMENT AND RECLAMATION COSTS[(2)] ($000s)	FUTURE NET REVENUE BEFORE INCOME TAXES ($000s)	FUTURE INCOME TAXES ($000s)	FUTURE NET REVENUE AFTER INCOME TAXES ($000s)
Proved Reserves	138,157	2,609	52,065	2,643	15,965	64,875	-	64,875
Proved Plus Probable Reserves	**179,726**	**3,406**	**68,365**	**2,696**	**17,333**	**87,925**	-	**87,925**

Notes:

(1) The estimated values of future net revenues disclosed do not represent fair market value.
(2) Reflects estimated abandonment and reclamation costs for wells (both existing and undrilled wells) with attributed reserves and for wells with no attributed reserves, facilities and infrastructure.

FUTURE NET REVENUE
BY PRODUCTION TYPE
as of December 31, 2019
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION TYPE	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000's)[2]	UNIT VALUE[3] ($)/BOE
Proved Reserves	Conventional Natural Gas[1]	45,158	16.04
	Shale Gas[1]	1,547	11.28
	Total	**46,706**	**15.81**
Proved Plus Probable Reserves	Conventional Natural Gas[1]	53,746	15.54
	Shale Gas[1]	1,843	10.87
	Total	**55,589**	**15.32**

Notes:

(1) Including by-products (including NGLs). The Reserves Report does not separately report on the Future Net Revenue for NGLs.
(2) Columns may not add due to rounding.
(3) Unit values are based on net reserve volumes.

Pricing Assumptions

The following tables set forth the benchmark reference prices, as at December 31, 2019, reflected in the Reserves Data. The forecast of prices, inflation and exchange rates provided in the table below were computed using the average of the forecasts by GLJ, McDaniel & Associates Ltd. and Sproule Associates Limited effective as at January 1, 2020.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS[1]
as of December 31, 2019
FORECAST PRICES AND COSTS

Year	Brent Blend Crude Oil FOB North Sea (US$/Bbl)	NYMEX Henry Hub ($US/MMBTU)	AGT Gas Price (US$/MMbtu)	McCully Gas Price[2] ($/Mcf)	Operating Cost Inflation Rates %/Year	Capital Cost Inflation Rates %/Year	Exchange Rate [3] ($US/$Cdn)
Forecast[4]							
2020	66.33	2.62	3.40	4.36	-	-	0.760
2021	67.94	2.87	3.65	4.65	1.7	1.7	0.770
2022	70.06	3.06	3.86	4.85	2.0	2.0	0.785
2023	71.66	3.17	4.05	5.10	2.0	2.0	0.785
2024	73.27	3.24	4.15	7.18	2.0	2.0	0.785
2025	74.57	3.32	4.23	7.82	2.0	2.0	0.785
2026	76.22	3.39	4.32	7.93	2.0	2.0	0.785
2027	77.83	3.46	4.40	8.05	2.0	2.0	0.785
2028	79.36	3.52	4.49	8.17	2.0	2.0	0.785
2029	80.92	3.60	4.58	8.29	2.0	2.0	0.785
2030	82.54	3.67	4.67	8.41	2.0	2.0	0.785
Thereafter	Escalation rate of 2.0%						

Notes:

(1) This summary table identifies benchmark reference pricing schedules that might apply to a reporting issuer.
(2) The forecast McCully gas price is used by GLJ in calculating the net present value of Headwater's future natural gas net revenues. The McCully gas price is determined by adjusting the forecast AGT gas prices to reflect the expected premiums received at Headwater's delivery point, transportation costs, as applicable, heat content and marketing conditions.
(3) The exchange rate used to generate the benchmark reference prices in this table.
(4) As at December 31, 2019.

Weighted average historical prices, excluding hedging and before transportation costs, realized for the year ended December 31, 2019, were CAD$6.49/Mcf for natural gas.

Reconciliation of Changes in Reserves

The following table sets out the reconciliation of the gross reserves of the Corporation as at December 31, 2019 as compared to December 31, 2018:

Reserves Reconciliation of Corporation Total Natural Gas Reserves
By Principle Product Type
(Forecast Prices and Costs)

	Conventional Natural Gas			**Shale Natural Gas**		
FACTORS	Gross Proved (MMcf)(3)	Gross Probable (MMcf)(3)	Gross Proved Plus Probable (MMcf)(3)	Gross Proved (MMcf)(3)	Gross Probable (MMcf)(3)	Gross Proved Plus Probable (MMcf)(3)
December 31, 2018(1)	17,114	4,005	21,119	824	211	1,035
Technical Revisions	1,201	15	1,216	51	(14)	38
Economic Factors	158	(99)	59	-	-	-
Production	(1,311)	-	(1,311)	(39)	-	(39)
December 31, 2019(2)	17,163	3,921	21,084	836	197	1,034

Reserves Reconciliation of Corporation Reserves
By Principle Product Type
(Forecast Prices and Costs)

	Natural Gas Liquids			**Total Oil Equivalent**		
FACTORS	Gross Proved (MBbl)(3)	Gross Probable (MBbl)(3)	Gross Proved Plus Probable (MBbl)(3)	Gross Proved (MBOE)(3)	Gross Probable (MBOE)(3)	Gross Proved Plus Probable (MBOE)(3)
December 31, 2018(1)	18	4	22	3,008	707	3,715
Technical Revisions	1	-	1	210	-	210
Economic Factors	-	-	-	26	(17)	10
Production	(1)	-	(1)	(226)	-	(226)
December 31, 2019(2)	18	4	22	3,018	691	3,709

Notes:

(1) As evaluated by GLJ as at December 31, 2018, using GLJ's forecast prices and costs as at such date.
(2) As evaluated in the Reserve Report.
(3) Columns may not add due to rounding.

Additional Information Relating to Reserves Data

Timing of Undeveloped Reserves Assignments

GLJ has not attributed any undeveloped reserves to Headwater's properties. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

On May 27, 2016, the Government of New Brunswick announced its decision to continue the moratorium on hydraulic fracturing for an indefinite period. Headwater believes that all undeveloped wells in the McCully Field require hydraulic fracture stimulation to be commercially productive. As a result of this announcement, Headwater's undeveloped wells requiring hydraulic fracture stimulations in New Brunswick no longer meet the necessary conditions to qualify as reserves and GLJ made the decision in June 2016 to eliminate all undeveloped reserves from its estimates of reserves.

See "*Risk Factors – Hydraulic Fracturing*" and "*Risk Factors – Exploration, Development and Production Risks*" and other factors noted in "*Risk Factors*".

Significant Factors or Uncertainties

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 become 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, commodity 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.

In addition, higher than estimated operating costs would substantially reduce Headwater netback, which in turn would reduce the amount of cash available for reinvestment in drilling opportunities. This becomes most relevant during periods of low commodity prices when profits are more significantly impacted by high costs.

On March 27, 2015, the Government of New Brunswick enacted An Act to Amend the Oil and Natural Gas Act which created a moratorium on all forms of hydraulic fracturing in New Brunswick. On May 27, 2016, the New Brunswick Government announced its decision to continue the moratorium for an indefinite period, though recent amendments suggest that exemptions may be available for operations in the Sussex region. Headwater believes that all undeveloped wells on its properties in New Brunswick require hydraulic fracture stimulation to be commercially productive. As a result of this announcement, Headwater has determined that it will not undertake any drilling or completion activities or incur associated capital expenditures in New Brunswick until the moratorium is lifted. As a result, Headwater's undeveloped wells requiring hydraulic fracturing no longer meet the necessary conditions to qualify as reserves. See "*Risk Factors – Hydraulic Fracturing*", "*Risk Factors – Risks Associated with Oil and Gas Exploration, Development and Production*" and other factors noted in "*Risk Factors*".

The total future abandonment and site reclamation costs are based on standard engineering techniques and management's estimate of costs to remediate, reclaim and abandon wells and facilities having regard to Headwater's working interest and the estimated timing of the costs to be incurred in future periods. Headwater has developed a process to calculate these estimates, which considers applicable regulations, actual and anticipated costs, type of well or facility and geographic location. Headwater estimates that the total cost to abandon and reclaim its midstream facilities and all wells drilled, producing and non-producing, as of December 31, 2019 is approximately $10.4 million on an undiscounted, uninflated basis. The abandonment and reclamation costs estimate includes three net wells in the Elgin Sub-Basin and 28 net wells in the McCully Field, Headwater's gas processing plant and transmission pipeline. Headwater anticipates spending approximately $0.1 million relating to reclamation work for previously abandoned wells in Prince Edward Island and in the McCully Field in the next three years. Future liabilities for abandonment and site reclamation costs are estimated by using standard engineering design cost estimating techniques. GLJ has determined that Headwater's estimates of McCully abandonment costs are reasonable and have included these costs in the Reserves Report. NI 51-101 requires the inclusion of all costs associated with the process of restoring property that has been disturbed by oil and gas activities to a standard imposed by applicable government or regulatory authorities. The abandonment cost estimates therefore include costs associated with the McCully wells, well pads and facilities. GLJ estimates in the Reserves Report that the total cost to abandon and reclaim all wells with reserves, wells with no attributed reserves, future development wells and related facilities is $17.3 million ($2.2 million at a 10% discount) for 31 net wells under the proved plus probable case and $16 million ($2.8 million at a 10% discount) for 31 net wells under the proved reserves case. GLJ's estimate of abandonment and reclamation costs for the McCully Field are included in the Reserves Report and therefore considered in their estimate of future net revenue.

Future Development Costs

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

	Forecast Prices and Costs	
Year	**Proved Reserves ($M)**	**Proved Plus Probable Reserves ($M)**
2020	-	-
2021	-	-
2022	-	-
2023	-	-
2024	2,643	-
Thereafter	-	2,696
Total: Undiscounted	2,643	2,696
Discounted 10%	1,721	1,596

Headwater's 2020 capital expenditure program does not include any capital spending in New Brunswick due to the hydraulic fracturing moratorium currently in effect in New Brunswick. Capital expenditures include anticipated costs for the continued production of the existing wells and upgrade of facilities. It is expected that such future development costs in the McCully Field will be funded through future cash flow from operations.

There can be no guarantee that funds will be available or that the Board will allocate funding to develop all of the reserves attributable in the Reserve Report. Failure to develop those reserves may have a negative impact on Headwater future cash flow.

The interest or other costs of external funding are not included in the reserves and future net revenue estimates set forth above and may reduce the reserves and future net revenue to some degree depending upon the funding sources utilized. Headwater does not anticipate that interest or other funding costs would make further development of any of the NGLs, natural gas and shale gas assets uneconomic.

Factors that could result in the change in timing or cancelled future developments are as follows:

- unanticipated facility failure that would change the timing of capital expenditures; and
- changing production conditions (such as producing pressures declining greater than anticipated, causing the need for more facility compression).

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

Other Oil and Gas Information

Description of Principal Properties

McCully Field

The McCully Field, located approximately 12 kilometres northeast of Sussex, New Brunswick, includes natural gas production from the Hiram Brook formation, a conventional tight sandstone, and a portion of the Frederick Brook shale, an unconventional shale resource. The McCully Field accounts for all of Headwater's current production and all of Headwater's reserves.

The Corporation's interests in the McCully Field consist of three petroleum and natural gas leases:

- 100% working interest in lease number 06-01 (40,930 acres). At the date hereof, seventeen wells are located on these lands.

- 50% working interest in lease number 06-02 (3,561 gross acres and 1,780 net acres). At the date hereof, twenty wells are located on these lands in which Headwater and Nutrien each hold a 50% working interest.
- 50% working interest in lease number 09-01 (36,531 gross acres and 18,265 net acres held jointly with Nutrien) where two wells are located.

As at the date hereof, 39 wells have been drilled in the McCully Field, all of which have encountered natural gas.

Headwater sells all of its share of the natural gas produced from the McCully Field to Repsol pursuant to a long-term agreement which became effective on April 1, 2009 and will terminate on April 1, 2024. Headwater's natural gas production has historically been sold in the New England market in the northeastern U.S. at prices referenced to AGT but has recently been expanded to include sales to local markets in the Maritimes given the decrease in natural gas production in Atlantic Canada. In 2018, Headwater and Repsol amended their long-term agreement to eliminate transportation charges on the Canadian portion of the M&NP from November 1, 2018 to April 1, 2024 in recognition of the changing market.

The production, transportation, processing and marketing of natural gas from Nutrien Ltd.'s ("**Nutrien**") share of the production from the McCully Field are subject to agreements with Nutrien. Nutrien's share of natural gas production is either taken in kind for use at the Nutrien potash mill, located near Sussex, New Brunswick or delivered to Headwater's midstream facilities for sale by Nutrien to the Maritimes market and New England market.

Elgin Sub-Basin

The Corporation's interests in the Elgin Sub-Basin in the Moncton basin in southeastern New Brunswick consist of a 100% working interest in consolidated lease ONG Lease 13-02C (135,920 gross acres) and includes a portion of the Frederick Brook shale prospect.

Since 2009, Headwater has been working to advance the commerciality of the Frederick Brook shale prospect. With a total thickness of up to 1,100 metres, the Frederick Brook shale represents a significant prospective natural gas resource. To date, thirteen wells have been drilled into the Frederick Brook shale. The information from these wells has enabled the Corporation to geologically map the Frederick Brook shale over a wide area, in excess of 20 kilometers laterally from the McCully Field eastward.

In 2014, the Corporation conducted a well re-entry and fracturing program to further evaluate the shale gas potential of the Frederick Brook shale. The results of the program demonstrated that the Frederick Brook shale is productive from at least six different sub-intervals across a distance of 25 kilometers, with four of these wells currently on production.

Oil and Gas Wells

The following table sets forth the number and status of wells as at December 31, 2019 in which Headwater has a working interest. All of the wells in which Headwater has an interest are located onshore in the Province of New Brunswick.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
New Brunswick	-	-	1.0	1.0	32.0	23.0	8.0	7.0
Total	-	-	1.0	1.0	32.0	23.0	8.0	7.0

Properties with no Attributed Reserves

The following table sets out the developed and undeveloped land holdings of Headwater as at December 31, 2019.

	Undeveloped Acres		Developed Acres		Total Acres	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
New Brunswick	209,823	191,556	7,118	5,338	216,941	196,894
Québec	123,550	123,550	-	-	123,550	123,550
Newfoundland and Labrador	127,948	127,948	-	-	127,948	127,948
Total	461,321	443,054	7,118	5,338	468,439	448,392

The license to explore 127,948 net acres of undeveloped land on the Old Harry prospect off the west coast of Newfoundland and Labrador in the Gulf of St. Lawrence expired on January 14, 2020.

Headwater plans to surrender approximately 123,550 net acres of undeveloped land in the Old Harry prospect in the Laurentian Channel in Québec.

No other rights to explore, develop and exploit undeveloped land holdings will expire before December 31, 2020.

Forward Contracts

Headwater's operational results and financial condition will be dependent upon the prices received for NGLs, natural gas and shale gas production. NGLs, natural gas and shale gas prices have fluctuated widely in recent years. Any upward or downward movement in NGLs, natural gas and shale gas prices could have an effect on Headwater financial condition. For details on the various factors affecting oil and natural gas prices, see "*Industry Conditions – Pricing and Marketing*".

Headwater has agreed to sell all of its natural gas produced from the McCully Field and surrounding areas in southern New Brunswick pursuant to a long-term agreement with Repsol, as recently amended. This agreement became effective on April 1, 2009 and provides Headwater with year-round access to natural gas markets in the Maritimes and New England in the U.S. northeast and allows it to receive corresponding market prices including those in periods of peak demand. The agreement provides the basis for Headwater to sell present and future production at market prices (referenced to AGT). Headwater recently entered into an agreement with Repsol to change the delivery location of its natural gas production to the local Maritimes market as opposed to the New England market in recognition of the changing market. The natural gas production will continue to be sold based on natural gas prices at AGT but without incurring Canadian transportation expenses on M&NP.

Headwater's hedging activities could expose Headwater to losses or gains. Headwater could be subject to credit risk associated with the parties with which it contracts. This credit risk will be mitigated by entering into contracts with only stable and creditworthy parties and through the frequent review of Headwater's exposure to these entities. For details of the Corporation's forward contracts see the Corporation's audited annual financial statements for the year ended December 31, 2019, which have been filed on SEDAR and may be viewed under the Corporation's profile at www.sedar.com. See "*Risk Factors – Hedging*".

Additional Information Concerning Abandonment and Reclamation Costs

For the purposes of estimating Reserves Data, abandonment and reclamation costs for all wells (both existing and undrilled wells) that have been attributed reserves and certain dedicated facilities have been taken into account. In addition, surface lease reclamation and the abandonment and reclamation of pipelines, non-dedicated facilities and for wells with no attributed reserves has also been included.

Using public data and the Corporation's own experience, the Corporation estimates the amount and timing of future abandonment and reclamation expenditures at a well. Wells within each operating area are assigned an average cost per well to abandon and reclaim the well. The estimated expenditures are based on current regulatory standards and actual abandonment and reclamation cost history.

The total future abandonment and site reclamation costs are based on standard engineering techniques and management's estimate of costs to remediate, reclaim and abandon wells and facilities having regard to Headwater's working interest and the estimated timing of the costs to be incurred in future periods. Headwater has developed a process to calculate these estimates, which considers applicable regulations, actual and anticipated costs, type of well or facility and geographic location.

Additional information related to the Corporation's estimated share of future environmental and reclamation obligations for the working interest properties (including all abandonment and reclamation costs associated with all existing wells, facilities and infrastructure) can be found in Headwater's audited financial statements for the year ended December 31, 2019 and the accompanying management's discussion and analysis, which have been filed on SEDAR and may be viewed under the Corporation's profile at www.sedar.com.

Tax Horizon

Headwater has approximately $159 million of tax pools available, consisting primarily of Canadian Exploration Expense, Canadian Development Expense, Canadian Oil and Gas Property Expense, Facilities and Equipment (Class 41), Transmission Pipeline (Class 1) and Other Equipment and CEC. No cash income taxes were recorded for the year ended December 31, 2019. Based upon Headwater's planned capital expenditures and various other assumptions, no cash income taxes are expected to be paid by Headwater in 2020. Given volatility of commodity prices and the various other factors that could affect the Corporation's tax horizon, it is uncertain when the Corporation will be obligated to pay cash income taxes. The level of capital expenditures and additional acquisitions completed by the Corporation, as well as a variety of other factors, impact the Corporation's tax horizon.

The GLJ Reserves Report estimates that the Corporation will never be taxable on a total proved reserves basis or a proved plus probable reserves basis. The GLJ Reserves Report does not include capital spending on projects that have not been assigned reserves. This additional spending could extend the Corporation's tax horizon.

Exploration and Development Activities

Headwater did not have any exploration of development activities in New Brunswick during the year ended December 31, 2019 and does not have any plans to conduct exploration and development activities in New Brunswick until the moratorium on hydraulic fracturing in New Brunswick is lifted.

Costs Incurred

The following tables summarize capital expenditures (excluding capitalized general and administrative and other expenses) related to activities attributable to the Corporation's oil and gas assets for the year ended December 31, 2019:

($ thousands)	**December 31, 2019**
Property Acquisition	
Proved Properties	-
Unproved Properties	-
Exploration Costs	391
Development Costs	206
Total capital expenditures	597

Production Estimates

The following table sets out the volume of working interest production estimated for the year ended December 31, 2020, which is reflected in the estimate of future net revenue for the Corporation's gross proved reserves and gross proved plus probable reserves disclosed in the tables contained under "*Disclosure of Reserves Data*". The McCully Field accounts for all of this production.

	Shale Natural Gas (Mcf/d)		Natural Gas Liquids (Bbls/d)		Conventional Natural Gas (Mcf/d)		Total (BOE/d)
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**
Proved							
Producing	240	235	7	7	7,161	7,007	1,241
Undeveloped	-	-	-	-	-	-	-
Total Proved	240	235	7	7	7,161	7,007	1,241
Total Probable	-	-	-	-	29	28	5
Total Proved Plus Probable	240	235	7	7	7,189	7,035	1,246

The production estimates noted above assume that Headwater produces volumes from its reserves continuously over the year. Headwater does not believe the volumes noted are reflective of the Corporation's expected operations during the year ended December 31, 2020. Headwater does not expect to produce continuously during the year and instead expects to employ an intermittent production strategy to capture seasonal premium prices. As a result, the production estimates provided in the GLJ Reserves Report do not reflect the actual production strategy that the New Management Team expects to incorporate for the year ended December 31, 2020.

Production History

The following table summarizes certain information in respect of production, prices received, royalties paid, operating expenses and resulting netback from the McCully Field for the periods indicated below.

	Quarter Ended 2019				Year Ended
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**Dec. 31, 2019**
Average Daily Production[(1)]					
Natural Gas (MMcf/d)	9.0	2.4	-	3.5	3.7
Natural gas liquids (bbl/d)	10.0	3.0	-	2.0	4.0
Combined (BOE/d)	1,510	401	-	586	620
Average Net Production Prices Received[(2)]					
Natural Gas ($/Mcf)	7.00	4.16	-	6.80	6.49
Natural gas liquids ($/bbl)	76.80	89.82	-	83.34	80.56
Combined ($/BOE)	63.17	26.92	-	55.62	55.52
Royalties Paid					
Combined ($/BOE) [(4)]	(1.17)	(0.53)	-	(0.96)	(1.02)
Production Costs[(2)(3)(4)]					
Combined ($/BOE)	(5.50)	(16.64)	-	(12.19)	(11.54)
Netback Received[(4)]					
Combined ($/BOE)	56.50	9.75	-	42.47	42.96

Notes:

(1) Before deduction of royalties.
(2) Production prices are after hedging and net of costs to transport the product to market.
(3) This figure includes all field operating expenses.
(4) Headwater did not record royalties and production costs on a commodity basis. Headwater only had nominal sales of natural gas liquids in 2019 and therefore information is provided on a boe basis.

DIRECTORS AND EXECUTIVE OFFICERS OF THE CORPORATION

The names, provinces and countries of residence of each of the directors and executive officers of the Corporation, positions held with the Corporation, and the period each has served as a director or executive officer of the Corporation are as follows:

Name and Place of Residence	Office Held
Neil J. Roszell Alberta, Canada	Chairman, Chief Executive Officer and a Director (since March 4, 2020)
Jason Jaskela Alberta, Canada	President, Chief Operating Officer and a Director (since March 4, 2020)
Ali Horvath, CPA, CA Alberta, Canada	Vice President, Finance and Chief Financial Officer (since March 4, 2020)
Terry Danku Alberta, Canada	Vice President, Engineering (since March 4, 2020)
Jon Grimwood Alberta, Canada	Vice President, Exploration (since March 4, 2020)
Scott Rideout Alberta, Canada	Vice President, Land (since March 4, 2020)
Martin Fräss-Ehrfeld London, England	Director (since June 14, 2011)
Chandra Henry(1)(2), CPA, CFA, ICD.D Alberta, Canada	Director (since March 4, 2020)
Phillip Knoll(3), P.Eng Alberta, Canada	Director (since September 21, 2010)
Stephen Larke(1)(2), B. Comm, ICD.D Alberta, Canada	Director (since March 4, 2020)
Kevin Olson(1)(3) Alberta, Canada	Lead Independent Director (since March 4, 2020)
David Pearce(2)(3) Alberta, Canada	Director (since March 4, 2020)
Edward (Ted) Brown Alberta, Canada	Corporate Secretary (since March 4, 2020)

Notes:

(1) Member of the Audit Committee.
(2) Member of Corporate Governance and Sustainability Committee.
(3) Member of the Reserves Committee.

Headwater's directors will hold office until the next annual general meeting of the Shareholders or until each director's successor is appointed or elected pursuant to the ABCA.

As at March 25, 2020, the directors and executive officers of Headwater, as a group, beneficially owned or controlled or directed, directly or indirectly, 30,998,403 Common Shares or approximately 21% of the issued and outstanding Common Shares.

Principal Occupation

Profiles of the directors and executive officers of Headwater and the particulars of their respective principal occupations during the last five years are set forth below.

Neil Roszell, Chairman, Chief Executive Officer and a Director

Mr. Roszell is a professional engineer with 29 years of industry experience. Mr. Roszell was the President and Chief Executive Officer of Raging River Exploration Inc. ("**Raging River**") from its incorporation until June 5, 2017 when he transitioned into the role of Executive Chairman and Chief Executive Officer until Raging River's sale to Baytex Energy Corp. ("**Baytex**") in August 2018, following which Mr. Roszell acted as Chairman of Baytex from August 22, 2018 until December 2019. Mr. Roszell was the President and Chief Executive Officer of Wild Stream Exploration Inc. ("**Wild Stream**") from October 2009 until the Arrangement was completed. He was also the President and Chief Executive Officer of Wild River Resources Ltd. ("**Wild River**") from February 2007 until July 2009. Mr. Roszell was the President and Chief Operating Officer of Prairie Schooner Energy Ltd. ("**Prairie Schooner**") from August 2004 until September 2006. Mr. Roszell was Vice President, Engineering of Great Northern Exploration Ltd. ("**Great Northern**") from September 2001 to June 2004. Mr. Roszell received a Bachelor of Applied Science degree in Engineering from the University of Regina in 1991.

Jason Jaskela, Vice President, Production and Chief Operating Officer

Mr. Jaskela is a professional engineer with 20 years of industry experience. Mr. Jaskela was the Vice President, Production of Raging River from March 2012 until March 17, 2014 when he expanded his role as Chief Operating Officer and held that position until Raging River's sale to Baytex in August 2018, following which he was the Executive Vice President and Chief Operating Officer at Baytex until September 2020. From October 2009 to April 2010 he held the position of Manager Engineering with Wild Stream and was the Vice President, Production of Wild Stream from April 2010 until the Arrangement was completed. Prior to Wild Stream, Mr. Jaskela held senior engineering roles with Encana Corporation (May 2000 to May 2006) and Mahalo Energy Ltd. (May 2006 to October 2009). Mr. Jaskela graduated with a Bachelor of Science degree in Engineering in 2000.

Ali Horvath, Chief Financial Officer and Vice President, Finance

Ms. Horvath was previously a founder and the Controller of Raging River and prior thereto a Senior Financial Accountant with Wild Stream. Ms. Horvath has a Bachelor of Management degree from the University of Lethbridge. Ms. Horvath is a Chartered Professional Accountant.

Terry Danku, Vice President, Engineering

Mr. Danku is a professional engineer with 18 years of industry experience. Mr. Danku held several officer positions at Raging River since joining the Corporation in April 2014, including Vice-President, Engineering, Vice-President, Business Development and, most recently, Vice-President, Exploitation. Previously, Mr. Danku held a Team Lead position at Surge Energy Inc. ("**Surge**") and Senior engineering roles at Pace Oil & Gas (April 2012 – October 2013), Wild Stream Exploration (May 2011 – March 2012) and Encana Corporation (July 2002 – April 2011). Mr. Danku graduated with a Bachelor of Science degree in Engineering in 2002.

Jon Grimwood, Vice President, Exploration

Mr. Grimwood was the Vice President of Exploration at Raging River from October 2, 2017 until Raging River's sale to Baytex in August 2018, following which Mr. Grimwood was the Vice President of Exploration at Baytex until September 2019. Mr. Grimwood served as the President at Iron Bridge Resources Ltd. (formerly known as RMP Energy Inc. and Orleans Energy Ltd) from February 28, 2017 to August 1, 2017 and also served as its Vice President of Exploration from May 2011 to February 28, 2017. He served as Manager of Exploration at Iron Bridge Resources Ltd. He started his career at Poco Petroleums Ltd. in 1997 and held positions of increasing responsibility at Burlington Resources Canada Ltd., Rider Resources Ltd., and Galleon Energy Inc. Mr. Grimwood earned a Bachelor of Science from Brandon University, a Masters Degree in Earth Sciences from the University of Waterloo and is a Registered Member of APEGGA.

Scott Rideout, Vice President, Land

Mr. Rideout is a landman with over 17 years of industry experience. Mr. Rideout was the Vice President of Land at Raging River from July 2014 until Raging River's sale to Baytex in August 2018, following which Mr. Rideout was the Vice President of Land at Baytex until January 2020. Mr. Rideout held roles of increasing responsibility at Surge from October 2010 until July 2014 where he most recently held the position of Manager, Business Development and Land. Prior to joining Surge he was a Land Negotiator at Galleon Energy Inc., Kereco Energy Ltd., Provident Energy Trust and Talisman Energy Inc.

Chandra Henry, Director

Ms. Henry is currently Chief Financial Officer and Chief Compliance Officer of Longbow Capital Inc. and formerly a director of Pengrowth Energy Corporation. Prior to her role with Longbow, Ms. Henry was the Chief Financial Officer of FirstEnergy Capital Corp. Ms. Henry has a Bachelor of Commerce degree from the University of Calgary and has earned the Chartered Professional Accountant (CPA, CA), Chartered Financial Analyst (CFA) and Institute of Corporate Directors (ICD.D) designations.

Martin Fräss-Ehrfeld, Director

Mr. Fräss-Ehrfeld has served on the Board since 2011 and is currently the Chairman of AVE Capital Limited, an investment advisory firm, providing investment services to The Children's Investment Fund Management (UK) LLP. Mr. Fräss-Ehrfeld has over 25 years or investment fund experience and a Masters degree (Distinction) in Economics and Management.

Phillip Knoll, Director

Mr. Knoll is a Professional Engineer and has been the President of Knoll Energy Inc. since 2006. Mr. Knoll served as interim Co-CEO of AltaGas Ltd. from July to December 2018. He was CEO of Headwater (formerly Corridor Resources Inc.) from October 2010 to September 2014. Prior thereto, Mr. Knoll held senior roles with a number of companies, including Duke Energy Gas Transmission, Maritimes & Northeast Pipeline, Westcoast Energy Inc., TransCanada Pipelines Limited and Alberta Natural Gas Company Ltd.

Stephen Larke, Director

Mr. Larke has over 20 years of experience in energy capital markets, including research, sales, trading and equity finance and currently serves on the board of Topaz Energy Corp. and Vermillion Energy Inc. He is formerly a Managing Director and Executive Committee member with Calgary-based Peters & Co. Limited. Mr. Larke has a Bachelor of Commerce degree (Distinction) from the University of Calgary and has earned the Chartered Financial Analyst (CFA) and Institute of Corporate Directors (ICD.D) designations. In addition, Mr. Larke is a Fundamentals of Sustainability Accounting (FSA) Credential Holder.

Kevin Olson, Director

Mr. Olson has over 25 years of industry experience and is currently President of Camber Capital Corp. Mr. Olson is a former board member of Baytex, Raging River, Wild Stream, Wild River and Prairie Schooner Petroleum Ltd. Mr. Olson has managed four early stage energy funds and served as a director of a variety of exploration and production companies and petroleum services companies. Formerly Mr. Olson was Vice-President, Corporate Finance at FirstEnergy Capital Corp. and Vice-President, Corporate Development for Northrock Resources Ltd. Mr. Olson holds a Bachelor of Commerce degree (Distinction) majoring in finance and accounting from the University of Calgary.

David Pearce, Director

Mr. Pearce has a Bachelor of Science in Mechanical Engineering (Honors) and has been a Deputy Managing Partner at Azimuth Capital Management (formerly KERN Partners) from November 2008 to present. Mr. Pearce is currently a director at Baytex. Mr. Pearce was also a director of Raging River (March 2012) until the sale to Baytex in August 2018). Most recently, Mr. Pearce was with Northrock Resources Ltd. from June 1999 to January 2008 where he held several senior officer positions and most recently was the President and Chief Executive Officer. Prior thereto, Mr. Pearce was Vice President, Corporate Development at Fletcher Challenge Canada.

Edward (Ted) Brown, Corporate Secretary

Mr. Brown is a partner in the law firm Burnet, Duckworth & Palmer LLP, where his practice concentrates in corporate finance, mergers and acquisitions and corporate governance. Mr. Brown has a Bachelor of Arts degree in Economics and Bachelor of Laws degree from the University of Manitoba.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

No current or proposed director or officer or securityholder holding a sufficient number of securities of Headwater to affect materially the control of Headwater has, within the last ten years prior to the date of this document, been a director, chief executive officer or chief financial officer of any issuer (including Headwater) that, (i) while the person was acting in the capacity as director, chief executive officer or chief financial officer, was the subject of a cease trade or similar order or an order that denied the company access to any exemption under securities legislation, that was in effect for a period of more than thirty (30) consecutive days; or (ii) was subject to an order that resulted, after the director, executive officer or securityholder holding a sufficient number of securities of Headwater to affect materially the control of Headwater ceased to be a director, chief executive officer or chief financial officer of an issuer, in the issuer being the subject of a cease trade or similar order or an order that denied the relevant issuer access to any exemption under securities legislation, for a period of more than thirty (30) consecutive days, which resulted from an event that occurred while that person was acting as a director, chief executive officer or chief financial officer of the issuer.

No current or proposed director or officer or security holder holding a sufficient number of securities of Headwater to affect materially the control of Headwater has, within the last ten years prior to the date of this document, been a director or executive officer of any company (including Headwater) that, while such person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement for compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

No current or proposed director or officer or securityholder holding a sufficient number of securities of Headwater to affect materially the control of Headwater has, within the last ten years prior to the date of this document, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, officer or securityholder.

No current or proposed director or officer or securityholder holding a sufficient number of securities of Headwater to affect materially the control of Headwater has been subject to: (i) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (ii) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

Some of the directors and officers of the Corporation are also directors, officers and/or promoters of other reporting and non-reporting issuers. Accordingly, conflicts of interest may arise which could influence these persons in evaluating possible acquisitions or in generally acting on behalf of the Corporation, notwithstanding that they are bound by the provisions of the ABCA to act at all times in good faith in the interest of the Corporation and to disclose such conflicts to the Corporation if and when they arise. To the best of their knowledge, the Corporation is not aware of the existence of any conflicts of interest between any of their directors and officers as of the date hereof.

DIVIDENDS

There are no restrictions in the Corporation's articles or elsewhere which could prevent the Corporation from paying dividends. The Corporation has not paid out any dividends on any of its securities since its inception. The directors of the Corporation will determine if, and when, dividends will be declared and paid in the future from funds properly applicable to the payment of dividends based on the Corporation's financial position at the relevant time. Any decision to pay dividends on the Common Shares will be made by the directors on the basis of the Corporation's earnings, financial requirements and other factors existing at such future time, including commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by the ABCA for the declaration and payment of dividends. All of the Common Shares will be entitled to an equal share in any dividends declared and paid.

DESCRIPTION OF SHARE CAPITAL

Common Shares

The authorized capital of the Corporation includes an unlimited number of Common Shares without nominal or par value of which, as at March 25, 2020, 144,326,994 Common Shares are issued and outstanding as fully paid and non-assessable. In addition, the Corporation has 21,739,130 Warrants and 1,225,002 stock options to purchase 22,964,132 Common Shares outstanding as of March 25, 2020.

The holders of Common Shares are entitled to dividends, if, as and when declared by the Board, to receive notice of and one vote per Common Share at meetings of the shareholders and, upon liquidation, to share equally in such assets of Headwater as are distributable to the holders of Common Shares.

MARKET FOR SECURITIES

The following table sets out the high and low trading prices and aggregate volume of trading of the Common Shares, as applicable, on all Canadian exchanges reported by the TSX from January 1, 2019 to March 24, 2020.

Price Range and Trading Volume

Period	High ($)	Low ($)	Volume
2019			
January	0.80	0.71	365,281
February	0.74	0.67	427,910
March	0.77	0.62	344,597
April	0.77	0.69	367,672
May	0.73	0.69	1,127,370
June	0.71	0.64	902,251
July	0.68	0.65	1,142,258
August	0.67	0.63	884,080
September	0.67	0.63	772,303
October	0.85	0.64	425,557
November	0.80	0.72	581,702
December	0.78	0.66	1,207,264
2020			
January	1.40	0.71	17,794,824
February	1.34	1.16	4,401,718
March (1 - 24)	1.26	0.85	2,175,725

RISK FACTORS

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

Public Health Crises

Global or national health concerns, including the outbreak of pandemic or contagious diseases, such as the current COVID-19, may adversely affect the Corporation

The Corporation's business, operations and financial condition could be materially adversely affected by the outbreak of epidemics or pandemics or other health crises. In December 2019, COVID-19 was reported to have surfaced in Wuhan, China. On January 30, 2020, the World Health Organization declared the outbreak a global health emergency and on March 11, 2020, the World Health Organization declared the outbreak a pandemic. Reactions across the globe to the spread of COVID-19 have led to, among other things, significant restrictions on travel, temporary business closures, quarantines and a general reduction in consumer activity. The outbreak has spread from China throughout Europe, the Middle East, Canada and the United States, amongst other countries, causing cities, provinces, states, countries and specific companies to impose unprecedented restrictions such as quarantines, business closures, shelter in place declarations and travel restrictions, amongst other measures in an attempt to slow the spread of COVID-19. While these effects are expected to be temporary, the duration of the business disruptions domestically and internationally and related financial impact cannot be reasonably estimated at this time and may last for an extended period of time. Similarly, the Corporation cannot estimate whether or to what extent this outbreak and the potential financial impact may extend to countries outside of those currently most heavily impacted. Such public health crises can result in volatility and disruptions in the supply and demand for oil and natural gas, global supply chains and financial markets, as well as declining trade and market sentiment and reduced mobility of people, all of which could affect commodity prices, interest rates, credit ratings, credit risk and inflation. In particular, oil prices have significantly weakened in response to the outbreak of COVID-19. See "– *Weakness and Volatility in the Oil and Natural Gas Industry*". The risks to the Corporation of such public health crises also include risks to employee health and safety and a slowdown or temporary suspension of operations in geographic locations impacted by an outbreak. At this point, the extent to which COVID-19 may impact the Corporation is uncertain; however, it is possible that COVID-19 may have a material adverse effect on the Corporation's business, results of operations and financial condition.

Global or national health concerns, including the outbreak of pandemic or contagious diseases, such as COVID-19, may adversely affect the Corporation by (i) reducing global economic activity thereby resulting in lower demand for crude oil, NGLs and natural gas, (ii) impairing its supply chain (for example, by limiting the manufacturing of materials or the supply of services used in the Corporation's operations), and (iii) affecting the health of its workforce, rendering employees unable to work or travel.

Should an employee or visitor in any of the Corporation's facilities, offices or work sites become infected with a serious illness that has the potential to spread rapidly, this could place the Corporation's workforce at risk. The 2020 outbreak of COVID-19 is one example of such an illness. The Corporation takes every precaution to strictly follow industrial hygiene and occupational health guidelines. Additionally, the Corporation follows posted health guidelines, as and when posted, to protect the health of its employees and decrease the potential impact of serious illness on its operations. There can be no assurance that this virus or another infectious illness will not impact the Corporation's personnel and ultimately its operations.

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

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

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

Weakness and Volatility in the Oil and Natural Gas Industry

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

Market events and conditions, including global excess oil and natural gas supply, actions taken by OPEC+, sanctions against, and civil unrest in, Iran and Venezuela, 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 COVID-19 pandemic) and political upheavals in various countries including growing anti-fossil fuel sentiment, have caused significant weakness and volatility in commodity prices. Through the first few months of 2020, oil prices deteriorated due to softening global demand caused by the COVID-19 pandemic. In March 2020, OPEC and Russia were unable to reach an agreement to further reduce oil production in response to the COVID-19 pandemic. Saudi Arabia responded by reducing its pricing and promising to increase production to over 10 million bbl/day. These actions led to the deepest drop in crude oil prices that global markets have seen since 1991. With the rapid spread of COVID-19 and additional oil supply expected to come on-stream over the near term, oil prices and global equity markets have deteriorated significantly and are expected to remain under pressure. The extreme supply / demand imbalance is anticipated to cause a reduction in industry spending in 2020. These events and conditions have caused a significant decrease in the valuation of oil and natural gas companies and a decrease in confidence in the oil and natural gas industry. These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. See "*Industry Conditions – Royalties and Incentives", "Industry Conditions – Regulatory Authorities and Environmental Regulation*", "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*", "*– Political Uncertainty*" and the other risk factors herein. In addition, the difficulties encountered by midstream proponents to obtain the necessary approvals on a timely basis to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the oil and natural gas industry in Western Canada has led to additional downward price pressure on oil and natural gas produced in Western Canada. The resulting price differential between Western Canadian Select crude oil, and Brent and West Texas Intermediate crude oil has created uncertainty and reduced confidence in the oil and natural gas industry in Western Canada. See "*Industry Conditions – Transportation Constraints and Market Access*".

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

Hydraulic Fracturing

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

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

New Brunswick

Headwater utilizes hydraulic fracturing in connection with its drilling and completion activities in New Brunswick. There has been public concern over the hydraulic fracturing process. Most of these concerns have raised questions regarding the drilling fluids used in the fracturing process, their effect on fresh water aquifers, the use of water in connection with completion operations, the ability of such water to be recycled, and induced seismicity associated with fracturing. The U.S. and Canadian federal governments and certain U.S. state and Canadian provincial governments are currently reviewing certain aspects of the scientific, regulatory and policy framework under which hydraulic fracturing operations are conducted. At present, most of these governments are primarily engaged in the collection, review and assessment of technical information regarding the hydraulic fracturing process and, with the exception of increased chemical disclosure requirements in certain of the jurisdictions in which the Corporation operates, have not provided specific details with respect to any significant actual, proposed or contemplated changes to the hydraulic fracturing regulatory construct.

However, certain environmental and other groups have suggested that additional federal, provincial, territorial, state and municipal laws and regulations may be needed to more closely regulate the hydraulic fracturing process, and have made claims that hydraulic fracturing techniques are harmful to surface water and drinking water sources and may contribute to earthquake activity particularly where in proximity to pre-existing faults.

It is anticipated that federal, provincial and state regulatory frameworks to address concerns related to hydraulic fracturing will continue to emerge. While the Corporation is unable to predict the impact of any potential regulations upon its business, the implementation of new laws, regulations or permitting regulations with respect to water usage or disposal, or hydraulic fracturing generally could increase the Corporation's costs of compliance, operating costs, the risk of litigation and environmental liability, or negatively impact the Corporation's production and prospects, any of which may have a material adverse effect on the Corporation's business, financial condition and results of operations.

The New Brunswick Government announced on May 27, 2016 that it would indefinitely continue a moratorium on hydraulic fracturing. In November 2018, the Government of New Brunswick expressed its intention to allow natural gas development in the Sussex region, where Headwater's properties are located. On June 5, 2019, the Government of New Brunswick amended the *Prohibition Against Hydraulic Fracturing Regulation* to allow the Minister of Natural Resources and Energy Development to exempt certain operations in the Sussex region from the moratorium, though regulatory certainty remains regarding the availability of such exemptions.

Headwater believes that all new wells on its properties in New Brunswick require hydraulic fracture stimulation to be commercially productive. As a result of this announcement, Headwater has determined that it will not undertake any drilling activities in New Brunswick until the moratorium is lifted. Should the moratorium not be lifted, Headwater's ability to increase production beyond current levels in the McCully Field and its ability to obtain a joint venture partner to develop the Frederick Brook prospect in the Elgin Sub-Basin will be materially and adversely affected.

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

Alberta

Minor earthquakes are common in certain parts of Alberta, and are generally clustered around the municipalities of Cardston, Fox Creek, Rocky Mountain House, Brazeau and Red Deer. Since 2015, the Alberta Energy Regulator ("**AER**") has introduced seismic protocols for hydraulic fracturing operators in the Fox Creek, Red Deer and Brazeau areas (the "**Seismic Protocol Regions**") – initially in response to significant induced seismic activity in the Duvernay formation in Fox Creek in February 2015. Further, the AER continues to monitor seismic activity around the province and may extend these requirements to other areas of the province if necessary.

In March 2018 and March 2019, two earthquakes felt in Red Deer and Sylvan Lake were characterized as seismic activity induced by hydraulic fracturing. In March 2019, the AER suspended an oil and natural gas company's operations in the area where the earthquake occurred, pending further investigation. In May 2019, the suspended oil and gas company was able to resume operations, with a risk assessment plan in place that was approved by the AER.

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

British Columbia

Due to seismic activity recorded in the Kiskatinaw Seismic Monitoring and Mitigation (the "**Kiskatinaw Area**"), in May 2018, the British Columbia Oil & Gas Commission (the "**B.C. Commission**") issued special notification and monitoring requirements for hydraulic fracturing operators in the Kiskatinaw Area. These requirements include, among others, the submission of a seismic monitoring and mitigation plan prior to conducting operations, pre-operation notification to both residents and the B.C. Commission, and the suspension of operations if a seismic event above a 3.0 magnitude occurs. On November 29, 2018 hydraulic fracturing the operations of an natural gas producer in the Montney area in British Columbia were suspended after a series of three seismic events, ranging from 3.4 to 4.5 in magnitude, linked by the B.C. Commission to hydraulic fracturing. The B.C. Commission allowed the natural gas producer to resume operations in the Montney on October 21, 2019, but their suspension demonstrates the B.C. Commission's willingness to enforce its enhanced regulatory requirements. The same natural gas producer was also suspended from using a wastewater disposal well in 2019 due to seismicity attributed to the use of that well, demonstrating that the B.C. Commission's monitoring and oversight of seismic risk is not limited to hydraulic fracturing.

In 2018, the Government of British Columbia commissioned an independent scientific review panel to analyze hydraulic fracturing in the province and determine, among other things, how British Columbia's regulatory framework can be improved to better manage safety and environmental risks resulting from hydraulic fracturing operations. The panel's recommendations included directing the Government of British Columbia to consider classifying hydraulic fracturing wastewater as hazardous waste, certain best practices for producers conducting hydraulic fracturing, and increased water and seismicity monitoring by the B.C. Commission in northeastern British Columbia. The implementation of new regulations or modification of existing regulations, in response to the panel's findings, may adversely affect the Corporation's business operation, financial condition, results of operations and prospects.

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

The Government of British Columbia has come under increased scrutiny for its enforcement of environmental assessment, safety and licensing requirements for dams companies have built in association with their hydraulic fracturing operations. Under the *Water Sustainability Act*, dams require a water licence. For dams over a certain size, dam-operators must comply with additional safety and reporting requirements set out in the *Dam Safety Regulation*.

Larger dams are also subject to an environmental assessment and approval under the *Environmental Assessment Act*. Despite these regulatory requirements, reports have surfaced indicating that a number of unlicensed dams throughout northeastern British Columbia have been constructed without the requisite regulatory authorization. While the B.C. Commission has issued compliance orders with respect to individual dams, it is uncertain how, and to what extent the relevant industry regulators will respond to this issue. The Corporation may face operational delays depending on the level of severity with which the overseeing regulatory authorities decide to address these unauthorized projects, particularly where the Corporation is not strictly complying with the current regulatory framework.

Prices, Markets and Marketing

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

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

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

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

In recent years, the price of natural gas in North America has been declining. However, the Corporation's natural gas production is sold to markets in New England, and more recently, the Maritimes, at prices referenced to AGT. The New England market, and recently the Maritimes market, have in recent years been characterized by excess demand during the winter season resulting in elevated prices for natural gas as compared to depressed prices in other areas of North America, and this excess demand is expected to continue until new pipeline infrastructure is available to increase the supply of natural gas into this market, especially given the end of offshore natural gas production in Atlantic Canada. While numerous projects are planned which could alleviate the supply constraints to the New England market, it is not known whether the required regulatory approvals will be received and, if the projects proceed, the timing of completion of these projects. The Corporation's ability to borrow and to obtain additional capital on attractive terms is also substantially dependent upon natural gas and oil prices and, in particular, natural gas prices in the New England market in northeastern United States.

See "*Industry Conditions – Transportation Constraints and Market Access*" and "– *Weakness and Volatility in the Oil and Natural Gas Industry*".

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

Exploration, Development and Production Risks

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

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

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

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

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

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

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

Market Price

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

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

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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

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

Political Uncertainty

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

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. Since the 2016 U.S. presidential election, the American administration has withdrawn the United States from the Trans-Pacific Partnership and the United States Congress has passed sweeping tax reform, which, among other things, significantly reduces U.S. corporate tax rates. This has affected the competitiveness of other jurisdictions, including Canada. In addition, the North American Free Trade Agreement ("**NAFTA**") has been renegotiated and on November 30, 2018, Canada, the U.S. and Mexico signed the Canada–United States–Mexico Agreement ("**USMCA**"). As of March 13, 2020, each of Canada, the United States and Mexico have ratified the USMCA and it will come into force on June 1, 2020. Until then, NAFTA will continue to govern trade relations among Canada, Mexico, and the United States. See "*Industry Conditions - The North American Trade Agreement and Other Trade Agreements*". The U.S. administration has also taken action with respect to reduction of regulation, which may also affect relative competitiveness of other jurisdictions. It is unclear exactly what other actions the U.S. administration will implement, and if implemented, how these actions may impact Canada and in particular the oil and natural gas industry. Any actions taken by the current U.S. administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and natural gas companies, including the Corporation.

In addition to the political disruption in the United States, the impact of the United Kingdom's exit from the European Union remains to be determined. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. Conflict and political uncertainty also continues to progress in the Middle East. To the extent that certain political actions taken in

North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement, it could have an adverse effect on the Corporation's ability to market its products internationally, increase costs for goods and services required for the Corporation's operations, reduce access to skilled labour and negatively impact the Corporation's business, operations, financial conditions and the market value of the Common Shares.

A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the oil and natural gas industry including the balance between economic development and environmental policy. Alberta elected a new government in 2019 that is supportive of the Trans Mountain Pipeline expansion project while a minority government in British Columbia remains opposed to the project and has attempted to regulate the transport of heavy oil products into and through British Columbia. In January 2020, the Supreme Court of Canada unanimously rejected the government of British Columbia's proposed regulation of the transport of heavy oil products into and through British Columbia; however, tensions remain high between provincial and federal governments. Continued uncertainty and delays have led to decreased investor confidence, increased capital costs and operational delays for producers and service providers operating in the jurisdiction. See "*Industry Conditions – Transportation Constraints and Market Access*" and "*Industry Conditions – Regulatory Authorities and Environmental Regulation – British Columbia*.

The federal Government was re-elected in 2019, but in a minority position. The ability of the minority federal government to pass legislation will be subject to whether it is able to come to agreement with, and garner the support of, the other elected parties, most of whom are opposed to the development of the oil and natural gas industry. The minority federal government will also be required to rely on the support of the other elected parties to remain in power, which provides less stability and may lead to an earlier subsequent federal election. Lack of political consensus, at both the federal and provincial level, continues to create regulatory 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 oil and natural gas industry. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation"*, "*Industry Conditions – Transportation Constraints and Market Access*", "*Industry Conditions – Curtailment*" and "*Industry Conditions – The North American Free Trade Agreement and Other Trade Agreements*".

The oil and natural gas industry has become an increasingly politically polarizing topic in Canada, which has resulted in a rise in civil disobedience surrounding oil and natural gas development – particularly with respect to infrastructure projects. Protests, blockades, and demonstrations have the potential to delay and disrupt the Corporation's activities. See "*Industry Conditions – Transportation Constraints and Market Access – Natural Gas*".

Gathering and Processing Facilities and Pipeline Systems

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

The Corporation delivers its products through gathering and processing facilities and pipeline systems. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities and pipeline systems. The lack of firm pipeline capacity, production limits and limits on availability of capacity in gathering and processing facilities continues to affect the oil and natural gas industry and limits the ability to transport produced oil and natural gas to market. However, in early 2020, the Supreme Court of Canada and the Federal Court of Appeal both dismissed challenges to Cabinet's approval of the Trans Mountain Pipeline expansion, and construction on the pipeline expansion is underway. See "*Industry Conditions – Transportation Constraints and Market Access*" and "*Industry Conditions – Curtailment*". In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability of oil and natural gas companies to export oil and natural gas, and could result in the Corporation's inability to realize the full economic potential of its products or in a reduction of the price offered for the Corporation's production. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the Corporation's production, operations and financial results. As a result, producers have considered rail lines as an alternative means of transportation. Announcements and actions taken by the federal government and the provincial governments of British Columbia, Alberta and Québec relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. On August 28, 2019, with the passing of Bill C-69, the *Canadian Energy Regulator Act* and the *Impact Assessment Act* came into force and the *National Energy Board Act* and the *Canadian Environmental Assessment Act, 2012* were repealed. In addition, the Impact Assessment Agency of Canada replaced the Canadian Environmental Assessment Agency. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*". The impact of the new federal regulatory scheme on proponents, and the timing for receipt of approvals, of major projects is unclear.

Competition

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

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

Cost of New Technologies

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

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

Alternatives to and Changing Demand for Petroleum Products

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

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

Regulatory

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

The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Corporation's costs, either of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Further, the ongoing third-party challenges to regulatory decisions or orders has reduced the efficiency of the regulatory regime, as the implementation of the decisions and orders has been delayed resulting in uncertainty and interruption to business of the oil and natural gas industry. See *"Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulations", "Industry Conditions – Curtailment"* and *"– Liability Management".*

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

Royalty Regimes

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

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

Environmental

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

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

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

Carbon Pricing Risk

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

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

Liability Management

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

Alberta, Saskatchewan and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its regulatory obligations. Changes to the Liability Management Rating Program (the "**AB LMR Program**") administered by the AER, or other changes to the requirements of liability management programs, may result in significant increases to the Corporation's compliance obligations. The impact and consequences of the Supreme Court of Canada's decision in *Redwater Energy Corporation (Re)* ("**Redwater**) on the AER's rules and policies, lending practices in the crude oil and natural gas sector and on the nature and determination of secured lenders to take enforcement proceedings are expected to evolve as the consequences of the decision are evaluated and considered by regulators, lenders and receivers/trustees. In addition, the AB LMR Program may prevent or interfere with the Corporation's ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and natural gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Program*".

Climate Change

Climate change may pose varied and far ranging risks to the business and operations of the Corporation, both known and unknown, that may adversely affect the Corporation's business, financial condition, results of operations, prospects, reputation and share price

Chronic Climate Change Risks

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

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

Concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels which has influenced investors' willingness to invest in the oil and natural gas industry. Historically, political and legal opposition to the fossil fuel industry focused on public opinion and the regulatory process. More recently, however, there has been a movement to more directly hold governments and oil and natural gas companies responsible for climate change through climate litigation. In November 2018, ENvironment JEUnesse, a Québec advocacy group, applied to the Québec Superior Court to certify all Québecois under 35 as a class in a proposed class action lawsuit against the Government of Canada for climate related matters. While the application was denied, the group has stated it plans to appeal. In January 2019, the City of Victoria became the first municipality in Canada to endorse a class action lawsuit against oil and natural gas producers for alleged climate-related harms. The Union of British Columbia Municipalities defeated the City of Victoria's motion to initiate a class action lawsuit to recover costs it claims are related to climate change.

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

Acute Climate Change Risk

Climate change has been linked to extreme weather conditions. Extreme hot and cold weather, heavy snowfall, heavy rainfall and wildfires may restrict the Corporation's ability to access its properties, cause operational difficulties including damage to machinery and facilities. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions. Certain of the Corporation's assets are located in locations that are proximate to forests and rivers and a wildfire or flood may lead to significant downtime and/or damage to such assets.

Moreover, extreme weather conditions may lead to disruptions in the Corporation's ability to transport produced oil and natural gas as well as goods and services in its supply chain.

Variations in Foreign Exchange Rates and Interest Rates

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

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

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

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

Substantial Capital Requirements

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

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

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

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

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

Additional Funding Requirements

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

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

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

New Credit Facility Arrangements

Once in place, a failure to comply with covenants under a credit facility could result in restricted access to additional capital or being required to repay all amounts owing thereunder

The Corporation does not currently have a credit facility but it is expected that a credit facility will be put into place during 2020. It is expected that the amount authorized under any credit facility will be dependent on the borrowing base determined by its lenders. The Corporation is required to comply with covenants under a credit facility 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 a credit facility, which could result in the Corporation being required to repay amounts owing thereunder. The acceleration of the Corporation's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, a credit facility 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.

Issuance of Debt

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

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

Hedging

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

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

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

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

Availability and Cost of Material and Equipment

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

Oil and natural gas exploration, development and operating activities are dependent on the availability and cost of specialized materials and equipment (typically leased from third parties) in the areas where such activities are conducted. The availability of such material and equipment is limited. An increase in demand or cost, or a decrease in the availability of such materials and equipment may impede the Corporation's exploration, development and operating activities.

Title to and Right to Produce from Assets

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

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

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

Reserves Estimates

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

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

- historical production from properties;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures;
- marketability of oil and natural gas;
- royalty rates; and

- the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

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

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

Geological complexities of the McCully Field make it difficult to predict the success of future exploration and development activities in the area. These complexities include the sporadic presence of over-pressured "perched" water in some portions of the reservoir, the presence of significant amounts of bitumen in some parts of the reservoir, as well as depositional and structural character of the reservoir.

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

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

Insurance

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

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

Non-Governmental Organizations

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

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

Reputational Risk Associated with the Corporation's Operations

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

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

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

Changing Investor Sentiment

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

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

Dilution

The Corporation may issue additional Common Shares, diluting current Shareholders

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

Management of Growth

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

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

Expiration of Licenses and Leases

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

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

Dividends

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

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

Litigation

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

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

Co-Existence with Mining Operations

The Corporation's activities may be affected by historical potash mining operations

Nutrien has historically conducted potash mining operations pursuant to a lease granted by the Government of New Brunswick that overlays a substantial portion of the McCully Field. In 2018, Nutrien permanently closed its potash facility after putting the operation on care and maintenance in early 2016. Applicable legislation requires that oil and gas activities not interfere with mining operations and that mining activities not interfere with oil and gas operations. The Corporation has to date succeeded in conducting its business activities in a manner that does not interfere with such mining operations. For example, several of the wells previously drilled by the Corporation have been drilled directionally to access natural gas beneath the potash mine. Notwithstanding the closure of the mining operations by Nutrien, there can be no assurance that the Corporation's future exploration and development activities will not be adversely affected as a result of the historical potash mining operations, including the possibility that a portion of the McCully Field may not be accessible for natural gas development.

Indigenous Claims

Indigenous claims may affect the Corporation

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

Breach of Confidentiality

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

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

Income Taxes

Taxation authorities may reassess the Corporation's tax returns

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

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

Third Party Credit Risk

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

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

Conflicts of Interest

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

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

Reliance on a Skilled Workforce and Key Personnel

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

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

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

Information Technology Systems and Cyber-Security

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

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

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

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

Social Media

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

Increasingly, social media is used as a vehicle to carry out cyber phishing attacks. Information posted on social media sites, for business or personal purposes, may be used by attackers to gain entry into the Corporation's systems and obtain confidential information. The Corporation periodically reviews, supervises, retains and maintains the ability to retrieve social media content. Despite these efforts, 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.

Forward-Looking Information

Forward-looking information may prove inaccurate

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

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

Expansion into New Activities

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

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

Project Risks

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

If and when the Corporation acquires assets in the western Canadian sedimentary basin, it is expected that the Corporation will manage a variety of small and large projects in the conduct of its business. Project interruptions may delay expected revenues from operations. Significant project cost overruns could make a project uneconomic. The Corporation's ability to execute projects and to market oil and natural gas will depend upon numerous factors beyond the Corporation's control, including:

- availability of processing capacity;
- availability and proximity of pipeline capacity;
- availability of storage capacity;
- effects of inclement and severe weather events, including fire, drought and flooding;
- availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- availability and productivity of skilled labour; and
- regulation of the oil and natural gas industry by various levels of government and governmental agencies.

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

Seasonality

Oil and natural gas operations are subject to seasonal weather conditions and, if applicable to the Corporation's operations in the future, the Corporation may experience significant operational delays as a result

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable which prevents, delays or makes operations more difficult.

Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. If and when the Corporation acquires assets in the western Canadian sedimentary basin, certain of the Corporation's oil and natural gas producing areas may be located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of impassable muskeg. Additionally, road bans and other restrictions generally result in a reduction of drilling and exploratory activities and could also result in the shut-in of some of the Corporation's production if not otherwise tied-in.

Waterflood

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

The Corporation may in the future undertake certain waterflooding programs, which would 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 would need to have access to sufficient volumes of water, or other liquids, to pump into the reservoir to increase the pressure in the reservoir. If and when applicable, there is no certainty that the Corporation would 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. In the future, if the Corporation is unable to access such water it may not be able to undertake waterflooding activities, which may reduce the amount of oil and natural gas that the Corporation is ultimately able to produce from its reservoirs. In addition, in the future, the Corporation may undertake certain waterflood programs that ultimately prove unsuccessful in increasing production from the reservoir and as a result have a negative impact on the Corporation's results of operations.

INDUSTRY CONDITIONS

Companies carrying on business in the crude oil and natural gas sector in Canada are subject to extensive controls and regulations imposed through legislation of the federal government and the provincial governments where the companies have assets or operations. While these regulations do not affect the Corporation's operations in any manner that is materially different than they affect other similarly-sized industry participants with similar assets and operations, investors should consider such regulations carefully. Although governmental legislation is a matter of public record, the Corporation is unable to predict what additional legislation or amendments governments may enact in the future.

The Corporation holds interests in natural gas properties, along with related assets, in the Canadian province of New Brunswick and expects to hold interests in the future in the Canadian provinces of Alberta, Saskatchewan and/or British Columbia. As a result, the following discussion of industry conditions contains those conditions applicable to the exploration, development and production of natural gas in New Brunswick, as well as those relating to crude oil and natural gas in Alberta, Saskatchewan and British Columbia.

The Corporation's assets and operations are regulated by administrative agencies deriving authority from underlying legislation. Regulated aspects of the Corporation's upstream crude oil and natural gas business include all manner of activities associated with the exploration for and production of crude oil and natural gas, including, among other matters: (i) permits for the drilling of wells; (ii) technical drilling and well requirements; (iii) permitted locations and access of operation sites; (iv) operating standards regarding conservation of produced substances and avoidance of waste, such as restricting flaring and venting; (v) minimizing environmental impacts; (vi) storage, injection and disposal of substances associated with production operations; and (vii) the abandonment and reclamation of impacted sites. In order to conduct crude oil and natural gas operations and remain in good standing with the applicable provincial regulatory scheme, producers must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance in this regard can be costly and a breach of the same may result in fines or other sanctions. The discussion below outlines certain pertinent conditions and regulations that impact the crude oil and natural gas industry in New Brunswick, Alberta, Saskatchewan and British Columbia.

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, including global events such as the outbreak of COVID-19. Worldwide supply and demand factors are the primary determinant of crude oil prices; however, regional market and transportation issues also influence prices. The specific price depends, in part, on crude oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, supply/demand balance and contractual terms of sale.

Natural Gas

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

Natural Gas Liquids

The pricing of condensates and other NGLs such as ethane, butane and propane sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such prices depend, in part, on the quality of the NGLs, price of competing chemical stock, distance to market, access to downstream transportation, length of contract term, supply/demand balance and other contractual terms.

Exports from Canada

On August 28, 2019, Bill C-69 came into force, replacing, among other things, the *National Energy Board Act* (the "**NEB Act**") with the *Canadian Energy Regulator Act* (Canada) (the "**CERA**"), and replacing the National Energy Board (the "**NEB**") with the Canadian Energy Regulator ("**CER**"). The CER has assumed the NEB's responsibilities broadly, including with respect to the export of crude oil, natural gas and NGLs from Canada. The legislative regime relating to exports of crude oil, natural gas and NGL from Canada has not changed substantively under the new regime.

Exports of crude oil, natural gas and NGLs 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**"). While the Part VI Regulation was enacted under the NEB Act, it will remain in effect until 2022, or until new regulations are made under the CERA. The CERA and the Part VI Regulation authorize crude oil, natural gas and NGLs exports under either short-term orders or long-term licences. For natural gas, the maximum duration of an export licence is 40 years; for crude oil and other gas substances (e.g. NGLs), the maximum term is 25 years. To obtain a crude oil export licence, a mandatory public hearing with the CER is required; however, there is no public hearing requirement for the export of natural gas and NGLs. Instead, the CER will continue to apply the NEB's written process that includes a public comment period for impacted persons. Following the comment period, the CER completes its assessment of the application and either approves or denies the application. The CER can approve an application if it is satisfied that proposed export volumes are not greater than Canada's reasonably foreseeable needs, and if the proposed exporter is in compliance with the CERA and all associated regulations and orders made under the CERA. Following the CER's approval of an export licence, the federal Minister of Natural Resources is mandated to give his or her final approval. While the Part VI Regulation remains in effect, approval of the cabinet of the Canadian federal government ("**Cabinet**") is also required. The discretion of the Minister of Natural Resources and Cabinet will be framed by the Minister of Natural Resources' mandate to implement the CERA safely and efficiently, as well as the purpose of the CERA, to effect "oil and natural gas exploration and exploitation in a manner that is safe and secure and that protects people, property and the environment".

The CER also has jurisdiction to issue orders that provide a short-term alternative to export licences. Orders may be issued more expediently, since they do not require a public hearing or approval from the Minister of Natural Resources or Cabinet. Orders are issued pursuant to the Part VI Regulation for up to one or two years depending on the substance, with the exception of natural gas (other than NGLs) for which an order may be issued for up to twenty years for quantities not exceeding 30,000 m^3 per day.

As to price, exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the CER and the federal government. The Corporation does not directly enter into contracts to export its production outside of Canada.

As discussed in more detail below, one major constraint to the export of crude oil, natural gas and NGLs outside of Canada is the deficit of overall pipeline and other transportation capacity to transport production from Western Canada to the United States and other international markets. Although certain pipeline and other transportation projects are underway, many contemplated projects have been cancelled or delayed due to regulatory hurdles, court challenges and economic and other socio-political factors. Major pipeline and other transportation infrastructure projects typically require a significant length of time to complete once all regulatory and other hurdles have been cleared. In addition, production of crude oil, natural gas and NGLs in Canada is expected to continue to increase, which may further exacerbate the transportation capacity deficit.

Transportation Constraints and Market Access

Pipelines

Producers negotiate with pipeline operators (or other transport providers) to transport their products to market on a firm or interruptible basis. 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 that can be reached in a cost-effective manner and the price received. Due 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.

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

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

With respect to the current state of the transportation and exportation of crude oil from Western Canada to domestic and international markets, the Enbridge Line 3 Replacement from Hardisty, Alberta, to Superior, Wisconsin, formerly expected to be in-service in late 2019, continues to experience permitting difficulties in the United States and is now expected to be in-service in the latter half of 2020. The Canadian portion of the replaced pipeline began commercial operation on December 1, 2019.

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of sustained political opposition in British Columbia, the federal government purchased the Trans Mountain Pipeline from Kinder Morgan Cochin ULC in August 2018. However, the Trans Mountain Pipeline expansion experienced a setback when, in August 2018, the Federal Court of Appeal identified deficiencies in the NEB's environmental assessment and the Government's Indigenous consultations. The Court quashed the accompanying certificate of public convenience and necessity and directed Cabinet to correct these deficiencies. On June 18, 2019, Cabinet re-approved the Trans Mountain Pipeline expansion and directed the NEB to issue a certificate of public convenience and necessity for the project. Ongoing opposition by Indigenous groups continues to affect the progress of the Trans Mountain Pipeline. Along with its approval of the expansion, the federal government also announced the launch of the first step of a multi-step process of engagement with Indigenous groups for potential Indigenous economic participation in the pipeline. Following a public comment period initiated after the approval, the NEB ruled that NEB decisions and orders issued prior to the Federal Court of Appeal decision quashing the original Certificate of Public Convenience and Necessity will remain valid unless the CER (having replaced the NEB) decides that relevant circumstances have materially changed, such that there is a doubt as to the correctness of a particular decision or order. Construction commenced on the Trans Mountain Pipeline in late 2019, and is proceeding concurrently alongside CER hearings with landowners and affected communities to determine the final route for the Trans Mountain Pipeline.

In December 2019, the Federal Court of Appeal heard a judicial review application brought by six Indigenous applicants challenging the adequacy of the federal government's further consultation on the Trans Mountain Pipeline expansion. Two First Nations subsequently withdrew from the litigation after reaching a deal with Trans Mountain. On February 4, 2020, the Federal Court of Appeal dismissed the remaining four appellants' application for judicial review, upholding Cabinet's second approval of the Trans Mountain Pipeline expansion from June 2019. The Federation of British Columbia Naturalists, an environmental group that was denied standing in the December 2019 judicial review, appealed the Federal Court of Appeal's standing decision to the Supreme Court of Canada. The appeal was dismissed on March 5, 2020.

In addition, on April 25, 2018, the British Columbia Government submitted a reference question to the British Columbia Court of Appeal, seeking to determine whether it has the constitutional jurisdiction to amend the *Environmental Management Act* (the "**BC EMA**") to impose a permitting requirement on carriers of heavy crude within British Columbia. The British Columbia Court of Appeal answered the reference question unanimously in the negative, and on January 16, 2020, the Supreme Court of Canada heard the Attorney General of British Columbia's appeal. The Supreme Court of Canada unanimously dismissed the appeal and adopted the reasons of the British Columbia Court of Appeal. See "– *Regulatory Authorities and Environmental Regulation – General – British Columbia*".

While it was expected that construction on the Keystone XL Pipeline, owned by the Canadian company TC Energy Corporation ("**TC Energy**") would commence in the first half of 2019, pre-construction work was halted in late 2018 when a United States Federal Court Judge determined the underlying environmental review was inadequate. The United States Department of State issued its final Supplemental Environmental Impact Statement in late 2019, and in January 2020, the United States Government announced its approval of a right-of-way that would allow the Keystone XL Pipeline to cross 74 kilometers of federal land. TC Energy announced in January 2020 that it plans to begin mobilizing heavy equipment for pre-construction work in February 2020, and that work on pipeline segments in Montana and South Dakota will begin in August 2020. Nevertheless, the Keystone XL pipeline remains subject to legal and regulatory barriers. In December 2019, a federal judge in Montana rejected the United States Government's request to dismiss a lawsuit by Native American tribes attempting to block required pipeline permits. The tribes claim that a permit issued in March 2019 would allow the pipeline to disturb cultural sites and water supplies in violation of tribal laws and treaties. Furthermore, the 1.9-kilometer long segment of the pipeline that will cross the Canada-United States Border remains dependant on the receipt of a grant of right-of-way and temporary use permit from the United States Bureau of Land Management and other related federal land authorizations.

Marine Tankers

Bill C-48 received royal assent on June 21, 2019, enacting the *Oil Tanker Moratorium Act*, which imposes a ban on tanker traffic transporting certain crude oil and NGLs products in excess of 12,500 metric tones to or from British Columbia's north coast. See "– *Regulatory Authorities and Environmental Regulation – General – Federal*".

Crude Oil and Bitumen by Rail

On February 19, 2019, the Government of Alberta announced that it would lease 4,400 rail cars capable of transporting 120,000 bbls/day of crude oil out of the province to help alleviate the high price differential plaguing Canadian oil prices. The Alberta Petroleum Marketing Commission would purchase crude oil from producers and market it, using the expanded rail capacity to transport the marketed oil to purchasers. However, in the spring of 2019, the Government of Alberta indicated that the rail program will be cancelled by assigning the transportation contracts to industry proponents. On February 11, 2020, the Government of Alberta announced that it had sold $10.6 billion worth of crude-by-rail contracts to the private sector.

In February 2020, the federal government announced that trains hauling more than 20 cars carrying dangerous goods, including crude oil and diluted bitumen, would be subject to reduced speed limits, following two derailments that led to fires and oil spills in Saskatchewan. These reduced speed limits will remain in effect until April 1, 2020.

Natural Gas

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 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 have also led to further reduced capacity and apportionment of firm access, which in Western Canada may be further exacerbated by natural gas storage limitations. However, in September 2019, the CER approved a policy change by TC Energy on its NOVA Gas Transmission Ltd. pipeline network, (which carries much of Alberta's gas production) to give priority to deliveries into storage. The change has served to somewhat stabilize supply and pricing, particularly during periods of maintenance on the system; however, the temporary policy change is expected to come to an end October 31, 2020. January 2020 has seen the narrowest price differential between Canadian and US Natural Gas benchmarks since early 2019.

Additionally, while a number of liquefied natural gas export plants have been proposed for the west coast of Canada, with 24 export licences issued since 2011, government decision-making, regulatory 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 liquefied natural gas export terminal announced a positive final investment decision to proceed with the project, which will allow LNG Canada to transport natural gas from northeastern British Columbia to the LNG Canada liquefaction facility and export terminal in Kitimat, BC, via the Coastal GasLink pipeline (the "**CGL Pipeline**"), which will be built and operated by TC Energy's subsidiary Coastal GasLink ("**CGL**"). Pre-construction activities began in November 2018, with a completion target of 2025. In late 2019, TC Energy announced that it would sell 65% of its interest in the CGL Pipeline, to investment companies KKR & Co Inc. and Alberta Investment Management Corporation while remaining the pipeline operator. The transaction is expected to close in the first half of 2020. The CGL Pipeline's route was altered as a result of feedback that LNG Canada received from Indigenous groups in the area, and on May 1, 2019, the B.C. Commission approved the current planned route for the CGL Pipeline. However, the CGL Pipeline has faced intense opposition. For example, a challenge to the approval process of the CGL Pipeline was launched in August 2018, contending that it should have been subject to the federal review instead of a provincial review. In July 2019, the NEB confirmed that the CGL Pipeline was properly subject to provincial jurisdiction. In addition, protests involving the Hereditary Chiefs of the Wet'suwet'en First Nation and their supporters have caused delays of construction activities on the CGL Pipeline. CGL obtained an injunction on December 31, 2019, and enforcement of the injunction started in February 2020. Since that time, there have been rail blockades and protests in support of the Hereditary Chiefs and their opposition to the CGL Pipeline. As a result of the opposition, the Federal Government met with the Hereditary Chiefs to negotiate a solution. The Federal Government and the Hereditary Chiefs did negotiate a deal but the details have not been announced and as such it is unknown what impact the deal could have on the CGL Pipeline and future resource projects involving lands subject to Indigenous land claims.

On February 19, 2020, the British Columbia Environmental Assessment Office (the "**EAO**") directed CGL to re-engage and consult further with Unist'ot'en, one of the Wet'suwet'en clans opposed to the pipeline route, regarding the impacts of the pipeline on a nearby healing centre. The EAO prescribed a 30-day timeline for the completion of these consultations and CGL is permitted to continue pre-construction work in the relevant area.

In December 2019, the CER approved a 40-year export licence for the Kitimat LNG project, a proposed joint venture between Chevron Canada Limited and Woodside Energy International (Canada Limited), a subsidiary of Australian Energy Ltd. This licence remains subject to Cabinet approval, and Chevron Canada Limited has indicated that it is interested in selling its 50 percent interest in Kitimat LNG. The Woodfibre LNG Project is a small-scale LNG processing and export facility near Squamish, British Columbia. The BC Oil and Gas Commission approved a project permit for Woodfibre LNG, a subsidiary of Singapore-based Pacific Oil and Gas Ltd. in July 2019. Pre-construction agreements for Woodfibre LNG are in the process of being revised and finalized. A project by GNL Québec Inc. is working through the federal impact assessment process for the construction and operation of a LNG facility and export terminal located on Saguenay Fjord, an inlet which feeds into the St. Lawrence River. The Goldboro LNG project, located in Nova Scotia, proposed by Pieridae Energy Ltd., would see LNG exported from Canada to European markets. Pieridae has agreements with Shell, upstream, and with Uniper, a German utility, downstream. The federal government has issued Goldboro LNG a 20-year export licence, and Pieridae Energy Ltd. has forecast a positive final investment decision for 2020. The Cedar LNG Project near Kitimat by Cedar LNG Export Development Ltd. is currently in the environmental assessment stage, with British Columbia's Environmental Assessment Office conducting the environmental assessment on behalf of the Impact Assessment Agency of Canada ("**IA Agency**").

Notwithstanding limited pipeline capacity in Canada that may have implications for the industry more broadly, the Corporation's operations are currently concentrated in New Brunswick and we project an excess of available capacity on the Canadian portion of the Maritimes and Northeast Pipeline ("**M&NP**") for the foreseeable future. The Corporation produces natural gas from its operations in the McCully Field near Sussex, New Brunswick, and sells all of its natural gas in the Maritimes and in New England, pursuant to a long-term agreement with Repsol, which includes transportation service on the segment of the M&NP that is located in the United States. The Corporation does not foresee any restricted access to American markets for the foreseeable future.

Enbridge Open Season

In early August 2019, Enbridge initiated an open season for the Enbridge mainline system, which has historically operated as a common carrier pipeline system, wherein producers could nominate volumes to ship through the pipeline. The changes that Enbridge intends to implement in the open season include the transition of the mainline system from a common carrier to a primarily contract carrier pipeline, wherein producers will have to commit to reserved space in the pipeline for a fixed term, with only 10% of available capacity reserved for nominations. As a result, shippers seeking firm capacity on the Enbridge system would no longer be able to rely on the nomination process and would have to enter long-term contracts for service.

Several shippers challenged Enbridge's open season and, in particular, Enbridge's ability to engage in an open season without prior regulatory approval. Following an expedited hearing process, the CER decided to shut down the open season, citing concerns about fairness and uncertainty regarding the ultimate terms and conditions of service.

On December 19, 2019, Enbridge applied to the CER for a hearing for the right to hold an open season. The CER is expected to establish a timeline for the process in early 2020. Interveners will have the opportunity to make written submissions, and then an oral hearing will take place later in the year. A final decision from the CER is expected in early 2021.

The North American Free Trade Agreement and Other Trade Agreements

NAFTA/ USMCA

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. Since coming into force, NAFTA has governed trade relations among its member countries. However, on November 30, 2018, Canada, Mexico, and the United States signed a new trade agreement, widely referred to as the United States Mexico Canada Agreement (the "**USMCA**"), sometimes referred to as the Canada United States Mexico Agreement, or "CUSMA".

As of March 13, 2020, each of Canada, the United States and Mexico have ratified the USMCA and it will come into force on June 1, 2020. Until then, NAFTA will continue to govern trade relations among Canada, Mexico, and the United States. As the United States remains Canada's primary trading partner and the largest international market for the export of crude oil, natural gas and NGLs from Canada, the implementation of the USMCA could have an impact on Western Canada's crude oil and natural gas industry at large, including the Corporation's business.

Article 605 of NAFTA (the proportionality clause) has historically prevented Canada from reducing oil and gas exports to the United States and Mexico relative to the total supply produced in Canada. Despite reducing crude oil production, the Government of Alberta's curtailment program has been compliant with NAFTA due to the operation of the proportionality rule. Reducing Canadian supply reduced Canada's required offering, thereby allowing Alberta to reduce production without causing Canada to breach its export obligations. However, the USMCA does not contain the proportionality rules of Article 605. The elimination of the proportionality clause removes a barrier in Canada's transition to a more diversified export portfolio. While diversification depends on the construction of infrastructure allowing more Canadian production to reach Eastern Canada, Asia, and Europe, the USMCA may allow for greater export diversification than currently exists under NAFTA.

Other Trade Agreements

Canada has also pursued a number of other international free trade agreements with other countries around the world. As a result, a number of free trade or similar agreements are in force between Canada and certain other countries while in other circumstances Canada has been unsuccessful in its efforts. 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 remains subject to ratification by 14 of the 28 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 on January 31, 2020, the United Kingdom and Canada are expected to work towards a new trade agreement through the 11-month implementation period, during which the United Kingdom will transition out of the European Union. As such, CETA will remain in place until December 31, 2020.

Canada and ten other countries have agreed on the text of the Comprehensive and Progressive Agreement for Trans-Pacific Partnership ("**CPTPP**"), which is intended to allow for preferential market access among the countries that are parties to the CPTPP. The CPTPP is in force among the first seven countries to ratify the agreement – Canada, Australia, Japan, Mexico, New Zealand, Vietnam, and Singapore.

While it is uncertain what effect CETA, CPTPP, or any other trade agreements will have on the crude oil 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

The provincial governments (i.e. the Crown) in western Canada own most of the mineral rights to crude oil and natural gas in their provinces, with the exception of Manitoba (which only owns 20% of the mineral rights). In New Brunswick, the Crown owns all mineral rights to crude oil and natural gas. 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. These rights are acquired through 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. 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.

On March 20, 2020, the Government of Alberta announced that all Crown mineral agreements with an expiration date in 2020 will be extended for one year, in response to the economic stress on Alberta's oil and natural gas producers caused by the COVID-19 pandemic. See "*Risk Factors – Weakness and Volatility in the Oil and Natural Gas Industry*".

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

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. British Columbia has a policy of "zone specific retention" that that allows a lessee to continue a lease for zones in which they can demonstrate the presence of oil or natural gas, with the remainder reverting to the Crown.

In addition to Crown ownership of the rights to crude oil and natural gas, private ownership of crude oil and natural gas (i.e. freehold mineral lands) also exists in Western Canada. In the provinces of Alberta, British Columbia, and Saskatchewan approximately 19%, 6% and 20%, respectively, of the mineral rights are owned by private freehold owners. Rights to explore for and produce such 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 crude oil and natural gas explorers and producers.

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

Until recently, oil and natural gas activities conducted on Indian reserve lands were governed by the *Indian Oil and Gas Act* (the "**IOGA**") and the *Indian Oil and Gas Regulations, 1995* (the "**1995 Regulations**"). In 2009, Parliament passed *An Act to Amend the Indian Oil and Gas Act*, amending and modernizing the IOGA (the "**Modernized IOGA**"), however the amendments were delayed until the federal government was able to complete stakeholder consultations and update the accompanying Regulations (the "**2019 Regulations**"). The Modernized IOGA and the 2019 Regulations came into force on August 1, 2019. At a high level, the Modernized IOGA and the 2019 Regulations govern both surface and subsurface IOGC Leases, establishing the terms and conditions with which an IOGC leaseholder must comply. The two enactments also establish a substitution system whereby provincial oil and natural gas/environmental regulatory authorities act on behalf of the federal government to ensure greater symmetry between federal and provincial regulatory standards. The Corporation does not have operations on Indian reserve lands.

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 a significant factor in the profitability of oil sands projects and crude oil, natural gas and NGLs production. Royalties payable on production from lands where the Crown does not hold the mineral rights are determined by negotiation between the mineral freehold owner and the lessee, 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 gross production. The rate of royalties payable typically depends in part on prescribed reference prices, well productivity, geographic location, field discovery date, method of recovery and the type or quality of the petroleum substance produced.

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

The federal government also announced in late 2018 that it would make $1.6 billion available to the oil and natural gas industry in light of worsening commodity price differentials. The aid package has been administered through federal agencies including the Business Development Bank of Canada, Natural Resources Canada, Export Development Canada, and Innovation, Science and Economic Development Canada. Export Development Canada has lent or guaranteed $629 million among 37 companies, of $1 billion available to oil and natural gas producers. The Bank of Canada has made 892 loans totalling $207.5 million out of its $500-million commercial loan allotment in the aid package. Innovation, Science and Economic Development Canada announced $49 million each for two projects to help Alberta companies building facilities to turn propane into polypropylene, a type of plastic not currently produced in Canada, but often used in packaging and labels. Natural Resources Canada distributed $37 million of a $50-million commitment under its Clean Growth Program for nine projects that help oil and natural gas companies reduce their carbon footprints.

Producers and working interest owners of crude oil and natural gas rights may also carve out 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.

New Brunswick

The Crown owns all crude oil and natural gas resources in New Brunswick. Though New Brunswick currently has no commercial crude oil production, the province calculates royalties on oil by assigning a sliding scale percentage to monthly production. The royalty percentage assigned to oil production ranges from 5% at production volumes of 1-49m^3, to 12% at volumes equal to or greater than 720 m^3.

Natural gas royalties in New Brunswick consist of a basic royalty component and an economic rent royalty component. Unlike other provinces, New Brunswick does not charge royalties on a per well basis, applying the royalty to a producer's aggregate production. The basic royalty is the greater of 4% of the product of the wellhead price of produced natural gas and all units of natural gas produced by the licensee or lessee in the province in that month, and 2% of a licensee's or lessee's monthly gross revenue from natural gas sales at all of its wells. The wellhead price is the selling price of natural gas minus transportation costs and a gas processing allowance. The economic rent royalty is 25% of the cumulative gross revenue from all of a licensee's or lessee's natural gas operations in New Brunswick, minus the sum of all capital expenditures and operating costs associated with those operations. Thus, the economic rent royalty will not come into effect until the licensee or lessee recovers all eligible costs and begins to make a profit.

The royalty on all by-products obtained in the production of oil and natural gas, including sulphur, helium, natural gas liquids and condensates is 10% of the greater of the actual selling price of those by-products, or their fair market value at the time and place of production.

Alberta

In Alberta, provincially-set royalty rates apply to Crown-owned mineral rights. In 2016, the Government of Alberta adopted a modernized royalty framework (the "**Modernized Framework**") that applies to all wells drilled after December 31, 2016. The previous royalty framework (the "**Old Framework**") will continue to apply to wells drilled prior to January 1, 2017 for a period of ten years ending on December 31, 2026. After the expiry of this ten-year period, these older wells will become subject to the Modernized Framework. The *Royalty Guarantee Act (Alberta),* came into effect on July 18, 2019, and provides that no major changes will be made to the current oil and natural gas royalty structure for a period of at least 10 years.

The Modernized Framework applies to all hydrocarbons other than oil sands which will remain subject to their existing royalty regime. Royalties on production from non-oil sands wells under the Modernized Framework are determined on a "revenue-minus-costs" basis with the cost component based on a Drilling and Completion Cost Allowance formula for each well, depending on its vertical depth and/or horizontal length. The formula is based on the industry's average drilling and completion costs as determined by the Alberta Energy Regulator (the "**AER**") on an annual basis.

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 of 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. 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 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 and, accordingly, they continue to pay the lower 5% royalty rate for a period of time after their wells achieve actual payout.

Oil and natural gas producers are responsible for calculating their royalty rate on an ongoing basis. The Crown's royalty share of production is payable monthly, and producers must submit their records showing the royalty calculation. The *Mines and Minerals Act* was amended in 2014, and shortened the window during which producers can submit amendments to their royalty calculations before they become statute-barred, from four years to three. Both the 2014 and 2015 production years became statute barred on December 31, 2018 as the pre-amendment four-year period applied for the years up to and including 2014. Going forward, producers will only have three years to amend their royalty calculations.

The Old Framework is applicable to all conventional crude oil and natural gas wells drilled prior to January 1, 2017 and bitumen production. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for conventional crude oil production under the Old Framework range from a base rate of 0% to a cap of 40%. Subject to certain available incentives, effective from the January 2011 production month, 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 metres deep, as well as the acid gas content of the produced gas. Under the Old Framework, the royalty rate applicable to NGLs is a flat rate of 40% for pentanes and 30% for butanes and propane. Currently, producers of crude oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, at a rate of $3.50 per hectare, and make monthly royalty payments in respect of crude oil and natural gas produced.

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.

Freehold mineral taxes are levied for production from freehold mineral lands on an annual basis on calendar year production. Freehold mineral taxes are calculated using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. On average, in Alberta the tax levied is 4% of revenues reported from freehold mineral title properties. The freehold mineral taxes would be in addition to any royalty or other payment paid to the owner of such freehold mineral rights, which are established through private negotiation.

British Columbia

Producers of crude oil in British Columbia receive royalty invoices each month for every well or unitized tract that is producing and/or reporting sales. The royalty calculation takes into account the production of crude oil on a well-by-well basis, which can be up to 40%, based on factors such as the volume of crude oil produced by the well or tract and the crude oil vintage, which depends on density of the substance and when the crude oil pool was located. Royalty rates are reduced on low-productivity wells and other wells with applicable royalty exemptions to reflect higher per-unit costs of exploration and extraction.

Producers of natural gas and NGLs in British Columbia receive royalty invoices each month for every well or unitized tract that is producing and/or reporting sales. Different royalty rates apply for natural gas, NGLs and natural gas by-products. For natural gas, the royalty rate can be up to 27% of the value of the natural gas and is based on whether the gas is classified as conservation gas or non-conservation gas, as well as reference prices and the select price. For NGLs and condensates, the royalty rate is fixed at 20%.

The royalties' payable by each producer will therefore vary depending on the types of wells and the characteristics of the substances being produced. Additionally, the Government of British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity natural gas wells. These include both royalty credit and royalty reduction programs.

Producers of crude oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For crude oil, the applicable freehold production tax is based on the volume of monthly production, which is either a flat rate, or, beyond a certain production level, is determined using a sliding scale formula based on the production level. For natural gas, the applicable freehold production tax is a flat rate, or, at certain production levels, is determined using a sliding scale formula based on a reference price, and depends on whether the natural gas is conservation gas or non-conservation gas. The production tax rate for freehold NGLs is a flat rate of 12.25%. Additionally, owners of mineral rights in British Columbia must pay an annual mineral land tax that is equivalent to $4.94 per hectare of producing lands. Non-producing lands are taxed on a sliding scale from $1.25 to $4.94 per hectare, depending on the total number of hectares owned by the entity.

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. 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 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 is subject to applicable deductions.

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

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, with targeted programs in effect for certain vertical crude oil wells, exploratory gas wells, horizontal crude oil and natural gas wells, enhanced crude oil recovery wells and high water-cut crude oil wells.

For production from freehold lands, producers must pay a freehold production tax, determined by first determining the Crown royalty rate, and then subtracting a calculated production tax factor. Depending on the classification of the petroleum substance produced, this subtraction factor may range between 6.9 and 12.5, however, in certain circumstances, the minimum rate for freehold production tax can be zero. This means that the ultimate tax payable to the Crown by producers on freehold lands will vary based on the underlying characteristics of the producer's assets.

Freehold and Other Types of Non-Crown Royalties

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 mineral freehold 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), producers of crude oil and natural gas from freehold lands in each of the Western Canadian provinces are required to pay freehold mineral taxes or production taxes. Freehold mineral taxes or production taxes are taxes levied by a provincial government on crude oil and natural gas production from lands where the Crown does not hold the mineral rights. A description of the freehold mineral taxes payable in each of the Western Canadian provinces is included in the above descriptions of the royalty regimes in such provinces.

Where 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 crude oil and natural gas industry is currently subject to environmental regulation under a variety of Canadian federal, provincial, territorial, and municipal laws and regulations, all of which are subject to governmental review and revision from time to time. Such regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain crude oil and natural gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment, and reclamation of well, facility and pipeline sites. Compliance with such regulations can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability, and the imposition of material fines and penalties. In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and GHG emissions including carbon dioxide equivalents ("**CO2e**"), may impose further requirements on operators and other companies in the crude oil and natural gas industry.

Federal

Canadian environmental regulation is the responsibility of both the federal and provincial governments. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law will prevail. The federal government has primary jurisdiction over federal works, undertakings and federally regulated industries such as railways, aviation and interprovincial transport including interprovincial pipelines.

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

Bill C-69 introduced a number of important changes to the regulatory regime for federally regulated major projects and associated environmental assessments. Previously, the NEB administered its statutory jurisdiction as an integrated regulatory body. Now, the CERA separates the CER's administrative and adjudicative functions. A board of directors and a chief executive officer will manage strategic, administrative and policy considerations while adjudicative functions will fall into the purview of a group of independent commissioners. The CER has assumed the jurisdiction previously held by the NEB over matters such as the environmental and economic regulation of pipelines, transmission infrastructure and offshore renewable energy projects, including offshore wind and tidal facilities. In its adjudicative role, the CERA tasks the CER with reviewing applications for the development, construction and operation of these projects, culminating in their eventual abandonment.

"Designated projects" under the IAA include interprovincial or international pipelines that require more than 75km of new right of way, and will require an impact assessment as part of their regulatory review. The impact assessment, conducted by a review panel, jointly appointed by the CER and the IA Agency, includes expanded criteria the review panel may consider when reviewing an application. The impact assessment also requires consideration of the project's potential adverse effects, the overall societal impact and the expanded public interest that a project may have. The impact assessment must look at the direct result of the project's construction and operation, including environmental, biophysical and socio-economic factors, including consideration of a gender-based analysis, climate change, and impacts to Indigenous rights. Designated projects include pipelines that require more than 75km of new right of way and pipelines located in national parks. Large scale in situ oil sands projects not regulated by provincial GHG emissions and certain refining, processing and storage facilities will also require an impact assessment.

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. Applications for non-designated projects will follow a similar process as under the NEB Act. There is significant uncertainty surrounding the impact of Bill C-69 on oil and natural gas projects. There was significant opposition from industry and others in respect of Bill C-69, and notwithstanding its stated purpose, there is concern that the changes brought about by Bill C-69 will result in projects not being approved or increased delays in approvals. The Minister of Natural Resources has a mandate to implement the CER efficiently and effectively, but the CER's ability to expedite the project approval process has not yet been substantially tested. The Government of Alberta is challenging the constitutionality of Bill C-69, and has submitted a reference question to the Alberta Court of Appeal. The case is expected to be heard in the fall of 2020.

On May 12, 2017, the federal government introduced Bill C-48 in Parliament. This legislation is aimed at providing coastal protection in northern British Columbia by prohibiting crude oil tankers carrying more than 12,500 metric tonnes of crude oil or persistent crude oil products from stopping, loading, or unloading crude oil in that area. Parliament passed Bill C-48 as the *Oil Tanker Moratorium Act* which received royal assent on June 21, 2019. The enactment of this statute may prevent pipelines from being built, and export terminals from being located on, the portion of the British Columbia coast subject to the moratorium (north of 50°53′00″ north latitude and west of 126°38′36″ west longitude) and, as a result, may negatively impact the ability of producers to access global markets.

New Brunswick

Oil and natural gas exploration in New Brunswick is regulated by the Department of Environment and Local Government, and the Department of Natural Resources and Energy Development. Environmental protection is legislated in the *Clean Air Act, Clean Water Act, Clean Environment Act*, and the associated regulations.

On February 15, 2013, New Brunswick released the "Responsible Environmental Management of Oil and Natural Gas Activities in New Brunswick", a document detailing the province's rules for the oil and gas industry. The document addresses several important areas of industry management including concerns associated with geophysical (seismic) testing, the escape of contaminants from the wellbore and well pad, greenhouse gas emissions, public safety and emergency planning, protecting communities and the environment, and reducing financial risk and protecting landowner rights.

In 2015, New Brunswick implemented the *Prohibition Against Hydraulic Fracturing Regulation*, banning all hydraulic fracturing in the province. The New Brunswick Government announced on May 27, 2016 that it would indefinitely continue a moratorium on hydraulic fracturing. In November 2018, the Government of New Brunswick expressed its intention to allow natural gas development in the Sussex region, where Headwater's properties are located. On June 5, 2019, the Government of New Brunswick amended the *Prohibition Against Hydraulic Fracturing Regulation* to allow the Minister of Natural Resources and Energy Development to exempt certain operations in the Sussex region from the moratorium, though regulatory certainty remains regarding the availability of such exemptions.

See "*Risk Factors – Hydraulic Fracturing*".

Alberta

The AER is the principal regulator responsible for all energy resource development in Alberta. It derives its authority from the *Responsible Energy Development Act* and a number of related legislation including the *Oil and Gas Conservation Act* (the "**OGCA**"), the *Oil Sands Conservation Act*, the *Pipeline Act*, and the *Environmental Protection and Enhancement Act*. The AER is responsible for ensuring the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as the Alberta Ministry of Energy's responsibility for mineral tenure. The objective behind a single regulator is an enhanced regulatory regime that is intended to be efficient, attractive to business and investors and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

On March 20, 2020, the Government of Alberta announced a $113 million contribution to the AER's industry levy, intended to provide financial relief in response to the economic stress and uncertainty facing Alberta's oil and natural gas industry as a result of the COVID-19 pandemic. See "*Risk Factors – Weakness and Volatility in the Oil and Natural Gas Industry*".

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

The Government of Alberta's land-use policy for surface land 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. As a result, several regional plans have been implemented. These regional plans may affect further development and operations in such regions.

The AER monitors seismic activity across Alberta, in the context of assessing the risks associated with, and instances of, earthquakes induced by hydraulic fracturing. Hydraulic fracturing is an important and common practice to stimulate production of oil and gas from dense subsurface rock formations. The process involves the injection of water, sand or other proppants and additives under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate oil and 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.

In an ongoing process spanning between February 19, 2015 to December 9, 2019, the AER has developed monitoring and reporting requirements that apply to all oil and natural gas producers working in certain areas where the likelihood of an earthquake is higher, and implemented the requirements in *Subsurface Order Nos. 2*, *6*, and *7*. The regions with seismic protocols in place that are aimed at limiting the impact and potential of induced earthquakes from hydraulic fracturing in the Seismic Protocol Regions. The Corporation does not have operations in the Seismic Protocol Regions. The AER may extend these requirements to other areas of Alberta if necessary, subject to the results of the AER's ongoing province-wide monitoring

British Columbia

In British Columbia, the *Oil and Gas Activities Act* (the "**OGAA**") impacts conventional crude oil and natural gas producers, shale gas producers and other operators of crude oil and natural gas facilities in the province. Under the OGAA, the B.C. Commission has broad powers, particularly with respect to compliance and enforcement and the setting of technical safety and operational standards for crude oil and natural gas activities. The *Environmental Protection and Management Regulation* establishes the government's environmental objectives for water, riparian habitats, wildlife and wildlife habitat, old-growth forests and cultural heritage resources. The OGAA requires the B.C. Commission to consider these environmental objectives in deciding whether or not to authorize a crude oil or natural gas activity. In addition, although not an exclusively environmental statute, the *Petroleum and Natural Gas Act*, in conjunction with the OGAA, requires proponents to obtain various approvals before undertaking exploration or production work, such as geophysical licences, geophysical exploration project approvals, permits for the exclusive right to do geological work and geophysical exploration work, and well, test hole and water-source well authorizations. Such approvals are given subject to environmental considerations and licences and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

Beginning in 2015, the British Columbia Government has introduced a regime to monitor and manage the risk of seismicity induced by the oil and natural gas industry, particularly in northern British Columbia, where hydraulic fracturing is used to access natural gas plays. The *Drilling and Production Regulation*, as amended in June 2015 requires and oil and gas producer to suspend its operations if they trigger an earthquake with a magnitude on the Richter scale of 4.0 or greater, and to implement mitigation measures approved by the B.C. Commission before resuming production. In June 2016, the B.C. Commission amended the permitting process to require all natural gas producers to conduct ground monitoring, and to submit a ground monitoring report within 30 days of completing hydraulic fracturing operations.

In May 2018, the B.C. Commission issued a Special Project Order under section 75 of the OGAA, which designated the Kiskatinaw Area. The B.C. Commission monitors Natural Resources Canada's reporting of seismicity across the province, and has installed additional seismograph stations in northeast British Columbia. Future earthquakes outside of the Kiskatinaw Area may trigger the introduction of similar requirements elsewhere in the province.

The British Columbia Government passed *Bill 51 – 2018: Environmental Assessment Act in* late 2018, which will replace the environmental assessment regime that has been in place since 2002. The updated *Environmental Assessment Act* came into force on December 16, 2019. The amendments will subject proposed projects to an enhanced environmental review process similar in substance to the federal environmental assessment process. The new environmental assessment process aims to enhance Indigenous engagement in the project approval process with an emphasis on consensus-building, in alignment with British Columbia's recent passage of Bill 41, which affirmed and adopted the United Nations Declaration on the Rights of Indigenous Peoples. Simultaneously with the enactment of the *Environmental Assessment Act*, the British Columbia Government enacted the accompanying *Reviewable Projects Regulation*, which sets out the projects subject to the new regime. The "project list" captures industrial, mining, energy, water management, waste disposal, transportation and other GHG intensive projects. In conducting an environmental assessment, the Environmental Assessment Office will consider the environmental, health, cultural, social and economic effects of a proposed project. However, many details of the new assessment process remain unknown, but the British Columbia Government has released a proposed timetable for the release of supplementary and informational materials through 2020.

In 2018, the British Columbia Government proposed amendments to the BC EMA that would see new heavy oil imports, whether by rail, expanded pipeline, or otherwise, managed through a discretionary permitting process (the "**Proposed Amendments**"). The Proposed Amendments would directly affect the transport of heavy oil blends across

British Columbia to tidewater through the Trans Mountain Pipeline. In its unanimous decision, the *Reference Re Environmental Management Act (British Columbia)* delivered May 24, 2019; the British Columbia Court of Appeal held that the Proposed Amendments are unconstitutional. The Supreme Court of Canada heard British Columbia's appeal on January 16, 2020, and found that, constitutionally, the British Columbia Government does not have the jurisdiction to make the Proposed Amendments. The Supreme Court of Canada unanimously dismissed the appeal and adopted the reasons of the British Columbia Court of Appeal. On January 29, 2020, the Government of British Columbia acknowledged that Canada's highest court has ruled in support of the Trans Mountain Pipeline expansion proceeding, and indicated that the Government of British Columbia would not initiate further challenges against the Trans Mountain Pipeline.

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 aim of the SKOGCA, and the associated regulations, is to provide resource companies investing in Saskatchewan's energy and resource industries with the best support services and business and regulatory systems available. The Government of Saskatchewan has implemented a number of operational requirements, including an increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers; and, procedural requirements including those related to Saskatchewan's participation as partner in the Petrinex Database.

Liability Management Rating Program

New Brunswick

Unlike other oil and natural gas producing provinces in Canada, New Brunswick does not administer a liability management or orphan well program. Instead, producers seeking to obtain licences or leases for exploration or production activities must provide a security deposit intended to backstop the licensee's ability to properly conduct any abandonment or reclamation activities. For well licences, applicants must also provide proof of and maintain liability insurance in the amount of $10,000,000. In addition, a licensee may only transfer its licence with the written approval of the Minister of Natural Resources and Energy Development.

Alberta

The AER administers the licensee Liability Management Rating Program (the "**AB LMR Program**"). The AB LMR Program is a liability management program governing most conventional upstream crude oil and natural gas wells, facilities and pipelines. It consists of three distinct programs: the Licensee Liability Rating Program (the "**AB LLR Program**"), the Oilfield Waste Liability Program (the "**AB OWL Program**") and the Large Facility Liability Management Program (the "**AB LFP**"). If a licensee's deemed liabilities in the AB LLR Program, the AB OWL Program and/or the AB LFP exceed its deemed assets in those programs, the AB LMR Program requires the licensee to provide the AER with a security deposit and may restrict the licensee's ability to transfer licences. This ratio of a licensee's assets to liabilities across the three programs is referred to as the licensee's liability management rating ("**LMR**"). Where the AER determines that a security deposit is required, the failure to post any required amounts may result in the initiation of enforcement action by the AER.

The AER previously assessed the LMR of all licensees on a monthly basis and posted the individual ratings on the AER's public website. However, in December 2019 the AER ceased posting the detailed LMR report, stating that resource and budget limitations have impacted its ability to maintain and administer the AB LMR Program. Licensees can continue to access their individual LMR calculations through the AER's Digital Data Submission System. The AER is currently reviewing the AB LMR Program as it no longer considers the LMR value alone to be a good indicator of a company's financial health. It is unclear if, or when, any changes will be made to the current regulatory framework. Any changes to the AB LMR Program may affect the Corporation's ability to obtain or transfer licenses.

Complementing the AB LMR Program, Alberta's OGCA establishes an orphan fund (the "**Orphan Fund**") to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program and the AB OWL Program if a licensee or working interest participant becomes insolvent or is unable to meet its obligations. Licensees in the AB LLR Program and AB OWL Program, including the Corporation, fund the Orphan Fund through a levy administered by the AER. A separate orphan levy applies to persons holding licences subject to the AB LFP. Collectively, these programs are designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines.

On January 31, 2019, the Supreme Court of Canada overturned the lower courts' decisions in Redwater, holding that there is no operational conflict between the abandonment and reclamation provisions contained in the provincial OGCA, the liability management regime administered by the AER and the federal bankruptcy and insolvency regime. As a result, receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets of a bankrupt licensee that have reached the end of their productive lives and represent a liability and deal with the company's valuable assets for the benefit of the company's creditors, without first satisfying abandonment and reclamation obligations.

In response to the lower courts' decisions in Redwater, the AER issued several bulletins and interim rule changes to govern the AER's administration of its licensing and liability management programs. Over the course of Redwater's trajectory through the Courts, the AER introduced amendments to its liability management framework. The AER amended its *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals*, which deals with licensee eligibility to operate wells and facilities, to require the provision of extensive corporate governance and shareholder information, including whether any director and officer was a director or officer of an energy company that has been subject to insolvency proceedings in the last five years. All transfers of well, facility and pipeline licences in the province are subject to AER approval. As a condition of transferring existing AER licences, approvals and permits, all transfers are now assessed on a non-routine basis and the AER now requires all transferees to demonstrate that they have an LMR of 2.0 or higher immediately following the transfer, or to otherwise prove to the satisfaction of the AER that it can meet its abandonment and reclamation obligations. The AER may make further rule changes at any time. The Supreme Court of Canada's Redwater decision alleviates some of the concerns that the AER's rule changes were intended to address, however the AER has indicated it is in the process of reviewing the current framework.

In early March 2020, the Government of Alberta announced an extension of an existing $235 million loan to the Orphan Fund by up to $100 million, earmarked for decommissioning approximately 1,000 wells and initiating reclamation on 1,000 sites.

The AER has also implemented the Inactive Well Compliance Program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under *Directive 013: Suspension Requirements for Wells* ("**Directive 013**"). The IWCP applies to all inactive wells that are noncompliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within five years. As of April 1, 2015, each licensee is required to bring 20% of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with *Directive 020: Well Abandonment*. The list of current wells subject to the IWCP is available on the AER's Digital Data Submission System. The AER has announced that from April 1, 2015 to April 1, 2016, the number of noncompliant wells subject to the IWCP fell from 25,792 to 17,470, with 76% of licensees operating in the province having met their annual quota. From April 1, 2016 to April 1, 2017, this number fell from 17,470 to 12,375 noncompliant wells, with 81% of licensees operating in the province having met their annual quota. The IWCP will complete its fifth year on March 31, 2020 but the AER has not released subsequent annual reports on compliance levels since 2017.

As part of its strategy to encourage the decommissioning, remediation and reclamation of inactive or marginal 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 though industry collaboration and economies of scale. Participants seeking the program incentives must commit to an inactive liability reduction target to be met through closure work of inactive assets. The Corporation is not currently participating in the voluntary ABC program.

British Columbia

Similar to Alberta, the B.C. Commission oversees a Liability Management Rating Program (the "**BC LMR Program**"), which is designed to manage public liability exposure related to crude oil and natural gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. Under the BC LMR Program, the B.C. Commission determines the required security deposits for permit holders under the OGAA. The LMR is the ratio of a permit holder's deemed assets to deemed liabilities. Permit holders whose deemed liabilities exceed deemed assets (i.e., an LMR of below a ratio of 1.0) will be considered at-risk and reviewed for a security deposit. Permit holders that fail to comply with security deposit requirements are deemed non-compliant under the OGAA and enter the compliance and enforcement framework.

As a result of certain amendments to the OGAA, on April 1, 2019 a liability-based levy paid to the Orphan Site Reclamation Fund ("**OSRF**") replaced the orphan site reclamation fund tax paid by permit holders. Similar to Alberta's Orphan Fund, the OSRF is an industry-funded program created to address the abandonment and reclamation costs for orphan sites. Permit holders are required to pay their proportionate share of the regulated amount of the levy, calculated using each permit holder's proportionate share of the total liabilities of all permit holders required to contribute to the fund. The OGAA permits the B.C. Commission to impose more than one levy in a given calendar year.

Effective May 31, 2019, the *Dormancy and Shutdown Regulation* (the "**Dormancy Regulation**") establishes the first set of legally imposed timelines for the restoration of oil and natural gas wells in Western Canada. The Dormancy Regulation classifies different sites based on activity levels associated with the well(s) on each site, with a goal of ensuring that 100% of currently dormant sites are reclaimed by 2036 with additional regulated timelines for sites that become dormant between 2019 and 2023 or become dormant after 2024. A permit holder will have varying reporting, decommissioning, remediation and reclamation obligations that depend on the classification of its sites. Any permit holder that has a dormant site in its portfolio must develop and submit an annual work plan to the B.C. Commission, outlining its decommissioning and restoration activities for each calendar year. The permit holder must also prepare and submit a retrospective annual report within 60 days of the end of the calendar year in which it conducted the work outlined in an annual work plan.

Saskatchewan

The Saskatchewan Ministry of Energy and Resources administrates the Licensee Liability Rating Program (the "**SK LLR Program**"). The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to the orphan fund (the "**Oil and Gas Orphan Fund**") established under the SKOGCA. The Oil and Gas Orphan Fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when the Saskatchewan Ministry of Energy and Resources confirms there is no legally responsible or financially able party to deal with the abandonment and/or reclamation responsibilities. The SK LLR Program requires a licensee whose deemed liabilities exceed its deemed assets (i.e., an LLR below 1.0) 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. On August 19, 2016, the Saskatchewan Ministry of the Economy released a notice to all operators introducing interim measures in response to Redwater. Among other things, the Saskatchewan Ministry of the Economy announced that it considers all licence transfer applications non-routine as it does not strictly rely on the standard LLR calculation in evaluating deposit requirements. In addition to increased security deposit requirements, the Saskatchewan Ministry of the Economy at that time announced in 2016 that it may incorporate additional conditions with licence transfer approvals.

Climate Change Regulation

Climate change regulation at both the federal and provincial level has the potential to significantly affect the future of the crude oil and natural gas industry in Canada. The impacts of federal or provincial climate change and environmental laws and regulations are uncertain. It is currently 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.

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 experiments with respect to climate governance. On April 22, 2016, 197 countries, including Canada, signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. As of December 23, 2019, 187 of the 197 parties to the convention have ratified the Paris Agreement. In December 2019, the United Nations annual Conference of the Parties took place in Madrid, Spain. The Conference concluded with the attendees delaying decisions about a prospective carbon market and emissions cuts until the next climate conference in Glasgow in 2020. However, the European Union reached an agreement about "The European Green New Deal" that aims to lower emissions to zero by 2050.

Following the Paris Agreement and its ratification in Canada, the Government of Canada pledged to cut its emissions by 30% from 2005 levels by 2030. Further, on December 9, 2016, the Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change (the "**Framework**"). The Framework provided for a carbon-pricing strategy, with a carbon tax starting at $10/tonne in 2018, increasing annually until it reaches $50/tonne in 2022. This system applies in provinces and territories that request it and in those that do not have a carbon pricing system in place that meets the federal standards. On June 21, 2018, the federal government enacted the *Greenhouse Gas Pollution Pricing Act* (the "**GGPPA**"), which came into force on January 1, 2019. This regime has two parts: an emissions trading system for large industry and a regulatory fuel charge imposing an initial price of $20/tonne of GHG emissions. Under current federal plans, this price will escalate by $10 per year until it reaches a price of $50/tonne in 2022. Starting April 1, 2020, the minimum price permissible under the GGPPA is $30/tonne of GHG emissions.

Seven provinces and territories have introduced carbon-pricing systems that meet federal requirements: British Columbia, Québec, Prince Edward Island, Nova Scotia, Newfoundland and Labrador, the Northwest Territories and Newfoundland. The federal fuel charge regime took effect in Saskatchewan, Manitoba and Ontario on April 1, 2019 and in the Yukon and Nunavut on July 1, 2019. The federal fuel charge regime took effect in Alberta on January 1, 2020. While New Brunswick was previously subject to the federal fuel charge, the federal government agreed to recognize the equivalency of New Brunswick's proposed fuel charge in December 2019. The New Brunswick fuel charge will take effect on April 1, 2020.

Alberta, Saskatchewan, and Ontario have referred the constitutionality of the GGPPA to their respective Courts of Appeal. In both the Saskatchewan and Ontario references, the appellate Courts ruled in favour of the constitutionality of the GGPPA. The Attorneys General of Saskatchewan and Ontario have appealed these decisions to the Supreme Court of Canada. The Court was set to hear the appeals in March 2020, but they have been tentatively postponed until June 2020 due to the COVID-19 outbreak. On February 24, 2020, the Alberta Court of Appeal determined that the GGPPA is unconstitutional. It is unclear whether the Alberta reference will be appealed and heard with the Saskatchewan and Ontario appeals. However, each of Saskatchewan, Ontario and Alberta will participate in the scheduled hearings, along with the Attorneys General of Quebec, New Brunswick, Manitoba and British Columbia and various other interested parties.

On April 26, 2018, the federal government passed the *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* (the "**Federal Methane Regulations**"). The Federal Methane Regulations seek to reduce emissions of methane from the crude oil and natural gas sector, and came into force on January 1, 2020. By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and intentional venting of methane, as well as ensuring that crude oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and natural gas facilities are permitted to vent. These facilities would need to capture the gas and either re-use it, re-inject it, send it to a sales pipeline, or route it to a flare. In addition, in provinces other than Alberta and British Columbia (which already regulate such activities), well completions by hydraulic fracturing would be required to conserve or destroy gas instead of venting. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

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

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

New Brunswick

In December 2016, New Brunswick released a climate change action plan, "Transitioning to a Low-carbon Economy" (the "**Transition Plan**"). Pursuant to this plan, the province announced that it intended to procure electricity from cleaner generation sources, including renewable sources and the use of renewable technologies, regulate GHG emissions from large industrial facilities, and reduce overall emissions in a manner that reflects the realities of the New Brunswick economy. Other initiatives under the plan include the phasing out of coal as a source of electricity, investing in new pollution-reduction technology, and increasing progress reporting and oversight by government committees.

The *Electricity Act* requires that 40% of electricity generation in New Brunswick be sourced from renewable generation by 2020.

On March 16, 2018, New Brunswick enacted the *Climate Change Act*, which became effective on January 1, 2016. Under the Climate Change Act, New Brunswick committed to lowering its GHG emissions to 14.8 megatonnes by 2020, 10.7 megatonnes by 2030, and 5 megatonnes by 2050, targets that were originally established in the Transition Plan. New Brunswick has already met its 2020 emissions reduction goal. The *Climate Change Act* also established a Climate Change Fund. The legislation did not immediately introduce a carbon pricing system or fuel charge levy. As a result, the output-based emissions trading program for large emitters and federal fuel charge levy applied in the province as of January 1, 2019 and April 1, 2019, respectively. However, the legislation did allow the New Brunswick Minister of Environment and Local Government to enter into agreements with the federal government regarding carbon pricing and funds generated from it.

On December 11, 2019, the federal government announced that it had accepted New Brunswick's proposed fuel charge program. On March 13, 2020, New Brunswick passed two Acts amending the *Gasoline and Motive Fuel Tax Act* (the "**GMTA**") to reflect the terms proposed to the federal government. These amendments received royal assent on March 17, 2020, and the New Brunswick fuel charge will take effect on April 1, 2020. Under the GMTA, a charge equivalent to the federal fuel charge will apply to the consumption of "carbon emitting products" in the province; however, the provincial government has lowered its excise tax on gasoline such that the net effect of the charge is a $0.02 per litre increase. All revenues from this charge will be invested in climate change initiatives. In addition, the provincial government will rebate the fuel charge on natural gas to Liberty Utilities, the provincial distributor of natural gas for utilities purposes, and is currently in discussions with Liberty Utilities to determine how that rebate will flow through to the end consumer.

On the same day that the amendments to the GMTA received royal assent, an *Act to Amend the Climate Change Act* also received royal assent. These amendments establish the framework for a provincially administered output-based pricing mechanism for industrial emitters. Under this program—deemed to have come into force on January 1, 2019—industrial facilities that emit more than 50,000 tonnes of CO2e per year will be subject to a mandatory emissions reduction requirements and charges for non-compliance. Facilities that emit more than 10,000 tonnes of CO2e but less than 50,000 CO2e may opt-in to the program. Facilities that fail to meet their targets may purchase credits to offset their surplus emissions and facilities that exceed their reductions targets can earn performance credits that they can then sell to other facilities. Specific targets and rates will be established by regulation, though none have been announced.

Alberta

On November 22, 2015, the Government of Alberta introduced a Climate Leadership Plan (the "**CLP**"). Under this strategy, the *Climate Leadership Act* (the "**CLA**") came into force on January 1, 2017 and established a fuel charge intended to first outstrip and subsequently keep pace with the federal price. On December 14, 2016, the *Oil Sands Emissions Limit Act* came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, excluding some attributable to upgraders, the electric energy portion of cogeneration and other prescribed emissions.

In June 2019, the Government of Alberta pivoted in its implementation of the CLP and repealed the CLA. The Carbon Competitiveness Incentives Regime ("**CCIR**") remained in place. As a result, the federally imposed fuel charge took effect in Alberta on January 1, 2020, at a rate of $20/tonne. In accordance with the GGPPA, this will increase to $30/tonne on April 1, 2020. However, on December 4, 2019, the federal government approved Alberta's proposed *Technology Innovation and Emissions Reduction* ("**TIER**") regulation intended to replace the CCIR, so the regulation of emissions from heavy industry remains subject to provincial regulation, while the federal fuel charge still applies. The TIER regulation came into effect on January 1, 2020.

The TIER regulation operates differently than the former facility-based CCIR, and instead applies industry-wide to emitters that emit more than 100,000 tonnes of CO2e per year in 2016 or any subsequent year. The 2020 target for most TIER-regulated facilities is to reduce emissions intensity by 10% as measured against that facility's individual benchmark (which is, generally, its average emissions intensity during the period from 2013 to 2015), with a further 1% reduction for each subsequent year. The facility-specific benchmark does not apply to all facilities. Certain facilities, such as those in the electricity sector, are compared against the good-as-best-gas standard, which measures against the emissions produced by the cleanest natural gas-fired generation system. 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. As with the former CCIR, the TIER regulation targets emissions intensity rather than total emissions. Under the TIER regulation, facilities in high-emitting sectors can opt-in to the program despite the fact that they do not meet the 100,000 tonne threshold. A facility can opt-in to TIER regulation if it competes directly against another TIER-regulated facility or if it has annual CO2e emissions that exceed 10,000 tonnes per year and belongs to an emissions-intensive or trade exposed sector with international competition. In addition, the owner of two or more "conventional oil and gas facilities" may apply to have those facilities regulated under the TIER regulation. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports and facilities that are unable to achieve their targets may either purchase credits from other facilities, purchase carbon offsets, or pay a levy to the Government of Alberta.

The Government of Alberta previously signaled its intention through the CLP to implement regulations that would 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*. The release of Directive 060 complements a previously released update to *Directive 017: Measurement Requirements for Oil and Gas Operations* that took effect in December 2018. Together, these new Directives represent Alberta's first step toward achieving its 2025 goal, as outlined in the Alberta Methane Regulations; however, the Government of Alberta and the federal government have not yet reached an equivalency agreement with respect to the Alberta Methane Regulations and the Federal Methane Regulations.

Alberta was also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed $1.24 billion through 2025 to fund two commercial-scale carbon capture and storage projects. Both projects will help reduce the CO2 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.

British Columbia

On August 19, 2016, the Government of British Columbia launched its Climate Leadership Plan, which aims to reduce British Columbia's net annual emissions by up to 25 million tonnes below current forecasts by 2050 and recommit the province to achieving its target of reducing emissions by 80% below 2007 levels by 2050.

British Columbia was also the first Canadian province to implement a revenue-neutral carbon tax. In 2012, the carbon tax was frozen at $30/tonne. However, the Government raised the carbon tax to $35/tonne in April 2018, and subsequently raised it to $40/tonne on April 1, 2019. The Government of British Columbia intends to continue raising its carbon tax in $5 increments until it reaches $50/tonne in 2021.

On January 1, 2016, the Greenhouse Gas Industrial Reporting and Control Act (the "**GGIRCA**") came into effect, which streamlined the regulatory process for large emitting facilities. The GGIRCA sets out various performance standards for different industrial sectors and provides for emissions offsets through the purchase of credits or through emission offsetting projects.

On December 5, 2018, the Government of British Columbia announced an updated clean energy plan, "**CleanBC**", which seeks to ensure that British Columbia achieves 75% of its GHG emissions reduction target by 2030. The CleanBC plan includes a number of strategies targeting the industrial, transportation construction, and waste sectors of the British Columbia economy. Key initiatives include: i) increasing the generation of electricity from clean and renewable energy sources; ii) imposing a 15% renewable content requirement in natural gas by 2030; iii) requiring fuel suppliers to reduce the carbon intensity of diesel and gasoline by 20% by 2030; iv) investing in the electrification of crude oil and natural gas production; v) reducing 45% of methane emissions associated with natural gas production; and vi) incentivizing the adoption of zero-emissions vehicles. The 2019 provincial budget provided $902 million over three years to support CleanBC, including electric vehicle rebates, incentives for making homes and businesses more energy efficient, and an enhanced climate action tax credit. On January 16, 2019, the B.C. Commission announced a series of amendments to the British Columbia *Drilling and Production Regulation* that will require facility and well permit holders to, among other things, reduce natural gas leaks and curb monthly natural gas emissions from their equipment and operations. These new rules came into effect on January 1, 2020.

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. Subsequently, the Government 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, 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 in December 18, 2018, establishing the framework of an output-based emissions management framework.

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

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

On October 1, 2019, *Bill 147 – An Act to amend The Oil and Gas Conservation Act*, was proclaimed into force that, in part, amends the SKOGCA to the extent necessary to bring it into alignment with the Saskatchewan O&G Emissions Regulations discussed above.

Accountability and Transparency

The federal Extractive Sector Transparency Measures Act (the "**ESTMA**") imposes mandatory reporting requirements on certain entities engaged in the commercial development of oil, gas or minerals, which includes exploration, extraction and holding permits to explore or extract. All companies subject to ESTMA are required to report payments over $100,000 made to any level of a Canadian or foreign government, including royalty payments, taxes (other than consumption taxes and personal income taxes), fees, production entitlements, bonuses, dividends (other than ordinary dividends paid to shareholders) and infrastructure improvement payments. These categories are distinct; regardless of the aggregate payment amount, one or more individual categories must reach the $100,000 threshold for reporting to be required.

It is worth noting that due to the definition of 'payee' under ESTMA, payments made to Aboriginal communities under impact-benefit agreements may be subject to reporting depending on whether the Aboriginal community with whom a company has negotiated, falls within this definition.

Any persons or entities found in violation of the ESTMA, including the making of a false report, failing to make the report public or failing to maintain records for the prescribed period, can be fined up to $250,000 for each day that the offence continues. There is a further fine of up to $250,000 for any person or entity who has structured payments in order to avoid the obligation to report such payments under the ESTMA. Officers or directors who authorized or acquiesced in the commission of an offence can be subject to personal liability, regardless of whether the entity for which they acted has been prosecuted or convicted. The ESTMA contains a due diligence defence whereby no person will be found guilty of an offence under the ESTMA if the person can establish that he or she exercised due diligence to avoid committing the offence. Additionally, there is a five year limitation period (from the time when the subject matter of the proceeding arouse) within which proceedings must be brought for offences under the ESTMA.

LEGAL PROCEEDINGS

Headwater is not a party to any legal proceeding nor was it a party to any legal proceeding during the 2019 financial year, nor is Headwater aware of any contemplated legal proceeding involving Headwater, its subsidiaries or any of its property which involves a claim for damages exclusive of interest and costs that may exceed 10% of the current assets of Headwater.

During the year ended December 31, 2019 and as at the date hereof, as applicable, there were and are: (i) no penalties or sanctions imposed against Headwater or 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 Headwater that would likely be considered important to a reasonable investor in making an investment decision; and (iii) no settlement agreements Headwater entered into before a court relating to a securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as described below or elsewhere herein, to the knowledge of management of the Corporation there were no material interests, direct or indirect, of directors or executive officers of the Corporation, of any shareholder who beneficially owns, directly or indirectly, or exercises control or direction over more than ten percent (10%) of the outstanding voting securities of the Corporation, or any other Informed Person (as defined in NI 51-102) or any known associate or affiliate of such persons, in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or would materially affect the Corporation or any of its subsidiaries.

Edward (Ted) Brown, the Corporate Secretary of Headwater, is a Partner of Burnet, Duckworth & Palmer LLP, which firm receives fees for legal services provided to Headwater.

AUDIT COMMITTEE INFORMATION

National Instrument 52-110 – *Audit Committees* ("**NI 52-110**") requires the Corporation, as a non-venture issuer, to disclose annually in its Annual Information Form certain information concerning the constitution of its audit committee and its relationship with its independent auditor in accordance with Form 52-110F1.

Audit Committee Mandate and Terms of Reference

The Mandate and Terms of Reference of the Audit Committee of the Board is attached hereto as Schedule "C".

Composition of the Audit Committee

The members of the Audit Committee are Chandra Henry (Chair), Kevin Olson and Steven Larke are considered independent in accordance with NI 52-110. All of the members of the Audit Committee are considered financially literate. Each of the members of the Audit Committee has identified themselves as financial experts due to their relevant education and experience. The following is a description of the education and experience of each member of the Audit Committee.

Name and Place of Residence	Independent	Financially Literate	Relevant Education and Experience
Chandra Henry Alberta, Canada	Yes	Yes	Ms. Henry is currently Chief Financial Officer and Chief Compliance Officer of Longbow Capital Inc. and formerly a director of Pengrowth Energy Corporation. Prior to her role with Longbow, Ms. Henry was the Chief Financial Officer of FirstEnergy Capital Corp. Ms. Henry has a Bachelor of Commerce degree from the University of Calgary and has earned the Chartered Professional Accountant (CPA, CA), Chartered Financial Analyst (CFA) and Institute of Corporate Directors (ICD.D) designations.
Kevin Olson Alberta, Canada	Yes	Yes	Mr. Olson has over 25 years of industry experience and is currently President of Camber Capital Corp. Mr. Olson is a former board member of Baytex, Raging River, Wild Stream, Wild River and Prairie Schooner Petroleum Ltd. Mr. Olson has managed four early stage energy funds and served as a director of a variety of exploration and production companies and petroleum services companies. Formerly Mr. Olson was Vice-President, Corporate Finance at FirstEnergy Capital Corp. and Vice-President, Corporate Development for Northrock Resources Ltd. Mr. Olson holds a Bachelor of Commerce degree (Distinction) majoring in finance and accounting from the University of Calgary.

Name and Place of Residence	Independent	Financially Literate	Relevant Education and Experience
Steven Larke Alberta, Canada	Yes	Yes	Mr. Larke has over 20 years of experience in energy capital markets, including research, sales, trading and equity finance and currently serves on the board of Topaz Energy Corp. and Vermillion Energy Inc. He is formerly a Managing Director and Executive Committee member with Calgary-based Peters & Co. Limited. Mr. Larke has a Bachelor of Commerce degree (Distinction) from the University of Calgary and has earned the Chartered Financial Analyst (CFA) and Institute of Corporate Directors (ICD.D) designations. In addition, Mr. Larke is a Fundamentals of Sustainability Accounting (FSA) Credential Holder.

Pre-Approval of Policies and Procedures

The Audit Committee has adopted a policy to review and pre-approve any non-audit services to be provided to the Corporation by the external auditors and consider the impact on the independence of such auditors. The Audit Committee may delegate to one or more independent members the authority to pre-approve non-audit services, provided that the member reports to the Audit Committee at the next scheduled meeting such pre-approval and the member comply with such other procedures as may be established by the Audit Committee from time to time.

External Auditor Service Fees

The Audit Committee has reviewed the nature and amount of non-audit services provided by PricewaterhouseCoopers LLP, Chartered Professional Accountants ("**PwC LLP**") to the Corporation to ensure auditor independence. Fees paid to PwC LLP for audit and non-audit services in the last fiscal year are outlined in the following table:

Nature of Services	Fees Paid to PwC LLP for Period Ended December 31, 2019	Fees Paid to PwC LLP for Period Ended December 31, 2018
Audit Fees(1)	$130,300	$145,551
Audit-Related Fees(2)	-	$11,251
Tax Fees(3)	$4,650	-
All Other Fees(4)	-	-
Total	$134,950	$156,802

Notes:

(1) "Audit Fees" include fees necessary to perform the annual audit and quarterly reviews of the Corporation's financial statements. Audit Fees include fees for review of tax provisions and for accounting consultations on matters reflected in the financial statements. Audit Fees also include audit or other attest services required by legislation or regulation, such as comfort letters, consents, reviews of securities filings and statutory audits.

(2) "Audit-Related Fees" include services that are traditionally performed by the auditor. These audit-related services include employee benefit audits, due diligence assistance, accounting consultations on proposed transactions, internal control reviews and audit or attest services not required by legislation or regulation.

(3) "Tax Fees" include fees for all tax services other than those included in "Audit Fees" and "Audit-Related Fees". This category includes fees for tax compliance ($4,650 2019/$nil 2018), tax planning ($nil 2019/$nil 2018) and tax advice ($nil2019/$nil 2018). Tax planning and tax advice includes assistance with tax audits and appeals, tax advice related to mergers and acquisitions, and requests for rulings or technical advice from tax authorities.

(4) "All Other Fees" include all other non-audit services.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of the Corporation are PwC LLP located at Suite 1101, 2000 Barrington St., Halifax, Nova Scotia B3J 3K1.

The transfer agent and registrar for the Common Shares is Computershare Trust Company of Canada at its principal offices located at 600, 530 – 8th Avenue S.W., Calgary, Alberta T2P 3S8.

MATERIAL CONTRACTS

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

INTEREST OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made by Headwater under NI51-102 during, or related to, Headwater's most recently completed financial year other than GLJ, the independent engineering evaluator for Headwater, and PwC LLP, the auditors for Headwater.

None of the principals of GLJ had any registered or beneficial interests, direct or indirect, in any of Headwater's securities or other property of Headwater or of Headwater's associates or affiliates either at the time they prepared the statement, report or valuation prepared by them, at any time thereafter or to be received by them. PwC LLP are the auditors of the Corporation and have confirmed with respect to the Corporation, that they are independent within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of Headwater, or of any of our associates or affiliates.

ADDITIONAL INFORMATION

Additional information relating to the Corporation can be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans will be contained in the Corporation's management information circular for the Corporation's next annual meeting of securityholders that involves the election of directors. Additional financial information is contained in the Corporation's financial statements and the related management's discussion and analysis for the Corporation's most recently completed financial year.

SCHEDULE "A"

FORM 51-101F3

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

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

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves Committee of the board of directors of the Company has

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

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

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

The Reserves Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves Committee, approved

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

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

(c) the content and filing of this report.

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

DATED as of this 25th day of March, 2020.

(signed) *"Neil Rozsell"*
Neil Roszell
Chief Executive Officer and Chairman

(signed) *"Jason Jaskela"*
Jason Jaskela
President and Chief Operating Officer

(signed) *"Kevin Olson"*
Kevin Olson
Director

(signed) *"David Pearce"*
David Pearce
Director

SCHEDULE "B"

FORM 51-101F2

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATORS

To the board of directors of Headwater Resources Inc. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2019. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019, 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, 2019, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue (before income tax, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
			M$	M$	M$	M$
GLJ Petroleum Consultants	December 31, 2019	Canada	Nil	55,589	Nil	55,589

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 reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.

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

EXECUTED as to our report referred to above:

GLJ PETROLEUM CONSULTANTS LTD., Calgary, Alberta, dated February 27, 2020.

Per: signed *"Jodi L. Anhorn"*
Jodi L.Anhorn, M. Sc., P.Eng.
President & CEO

SCHEDULE "C"

HEADWATER EXPLORATION INC.
AUDIT COMMITTEE MANDATE

1. **Establishment Audit Committee:** The board of directors (the "**Board**") of Headwater Exploration Inc. (the "**Corporation**") hereby establishes a committee to be called the Audit Committee (the "**Committee**").

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

   The Board may from time to time designate one of the members of the Committee to be the Chair of the Committee.

3. **Role and Objective:** The Committee shall, in addition to any other duties and responsibilities specifically delegated to it by the Board, generally assume responsibility for oversight of the following:

   (a) nature and scope of the annual audit;

   (b) the oversight of management's reporting on internal accounting standards and practices;

   (c) the review of financial information, accounting systems and procedures;

   (d) financial reporting and financial statements,

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

   The primary objectives of the Committee are as follows:

   (a) to assist the Board in meeting its responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of the Corporation and related matters;

   (b) to provide better communication between directors and external auditors;

   (c) to ensure the external auditor's independence;

   (d) to increase the credibility and objectivity of financial reports; and

   (e) to strengthen the role of the independent directors of the Corporation by facilitating in-depth discussions between directors of the Committee, management of the Corporation and external auditors.

4. **Mandate and Responsibilities of Committee:** The Committee will have the authority and responsibility to:

(a) oversee the work of the external auditors, including the resolution of any disagreements between management and the external auditors regarding financial reporting;

(b) satisfy itself on behalf of the Board with respect to the Corporation's internal control systems identifying, monitoring and mitigating business risks; and ensuring compliance with legal, ethical and regulatory requirements;

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

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

  (ii) reviewing significant accruals, reserves, estimates (such as the ceiling test calculation) and judgments made by management in preparation of financial statements and the appropriateness of such accruals, reserves, estimates and judgments;

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

  (iv) ascertaining compliance with covenants under loan agreements;

  (v) reviewing disclosure requirements for commitments and contingencies;

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

  (vii) reviewing unresolved differences between management and the external auditors; and

  (viii) obtain explanations of significant variances with comparative reporting periods.

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

(e) with respect to the appointment of external auditors by the Board:

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

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

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

  (iv) 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;

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

(vi) 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;

(f) review with external auditors (and internal auditor if one is appointed by the Corporation) their assessment of the internal controls of the Corporation, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses;

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

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

(i) establish a procedure for:

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

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

(j) review and approve the Corporation's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of the Corporation.

5. **Meeting Administrative Matters:** The following general provisions shall have application to the Committee:

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

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

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

(d) Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee will be taken. The Chief Financial Officer of the Corporation will attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.

(e) The Committee will meet with the external auditor in camera at least once per quarter (in connection with the preparation of the annual and interim financial statements) and at such other times as the external auditor and the Committee consider appropriate.

(f) Agendas will be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.

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

(h) Minutes of the Committee will be recorded and maintained and circulated to directors who are not members of the Committee as requested.

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

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

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

(l) Any issues arising from these meetings that bear on the relationship between the Board and management should be communicated to the Chairman of the Board or the Lead Independent Director by the Committee Chair.

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