



**HEADWATER EXPLORATION INC.**

**ANNUAL INFORMATION FORM**

Year Ended December 31, 2021

Dated March 10, 2022

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## ABBREVIATIONS AND CONVERSIONS

<b>Oil and Natural Gas Liquids</b>		<b>Natural Gas</b>	
Bbl	barrel	Mcf	thousand cubic feet
Bbls	barrels	MMcf	million cubic feet
MBbls	thousand barrels	Mcf/d	thousand cubic feet per day
MMBbls	million barrels	MMcf/d	million cubic feet per day
Mstb	1,000 stock tank barrels	MMbtu	million British Thermal Units
Bbls/d	barrels per day	Bcf	billion cubic feet
BOPD	barrels of oil per day	GJ	gigajoule
NGLs	natural gas liquids	MM	Million
STB	standard tank barrels		

### **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
m <sup>3</sup>	cubic metres
MBOE	1,000 barrels of oil equivalent
MMBOE	1,000,000 barrels of oil equivalent
Mcfe	thousand of cubic feet equivalent
NYMEX	New York Mercantile Exchange
\$000s	thousands of dollars
\$M	thousands of dollars
\$MM	millions of dollars
WCS	Western Canadian Select, a heavy sour Canadian crude oil blended at Port Hardisty, Alberta with a nominal API gravity of 20.5 degrees
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 Mcfes may be misleading, particularly if used in isolation. A BOE and Mcfe 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.**

<b>To Convert From</b>	<b>To</b>	<b>Multiply By</b>
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
Bbls	cubic metres	0.159
cubic metres	Bbls 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 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 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;

"**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**" 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;

"**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;

"**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.

### **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;

"**Acquired Assets**" has the meaning ascribed thereto under the heading "*General Development of the Business – Year 2020 – Transaction with Cenovus*";

"**AER**" means the Alberta Energy Regulator;

"**Annual MD&A**" means management's discussion and analysis of the Corporation for the year ended December 31, 2021;

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

"**Cenovus**" means Cenovus Energy Inc.;

"**Cenovus Transaction**" has the meaning ascribed thereto under the heading "*General Development of the Business – Year 2020 – Transaction with Cenovus*";

"**Cenovus Warrants**" has the meaning ascribed thereto under the heading "*General Development of the Business – Year 2020 – Transaction with Cenovus*";

"**CMHP**" has the meaning ascribed thereto under the heading "*General Development of the Business – Year 2021 – Exercise of Cenovus Warrants*";

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

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

"**Development Agreement**" has the meaning ascribed thereto under the heading "*General Development of the Business – Year 2020 – Transaction with Cenovus*";

"**GLJ**" means GLJ Ltd.;

"**GLJ Report**" means the independent reserves assessment prepared by GLJ dated February 10, 2022 evaluating the oil and gas properties of the Corporation as at December 31, 2021;

"**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;

"**Investor Agreement**" has the meaning ascribed thereto under the heading "*General Development of the Business – Year 2020 – Transaction with Cenovus*";

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

"**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 were 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;

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

"**Royalty Agreement**" has the meaning ascribed thereto under the heading "*General Development of the Business – Year 2020 – Transaction with Cenovus*";

"**Secondary Offering**" has the meaning ascribed thereto under the heading "*General Development of the Business – Year 2021 – Secondary Offering of Common Shares*";

"**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 (5<sup>th</sup> 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 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;

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

**"Warrants"** means the common share purchase warrants issued under the Unit Private Placement, each Warrant entitling the holder to purchase one (1) 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, for Warrants issued under the Unit Private Placement.

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

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

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 potential for the Corporation to pursue further development of the McCully Field assets to supply natural gas to the undersupplied market in Atlantic Canada; Headwater's intent to provide attractive long-term shareholder returns by focusing on asset quality and sustainability while maintaining a pristine balance sheet; Headwater's intent to actively pursue strategic acquisitions with synergistic characteristics such as existing long life producing assets or opportunities with significant, low risk upside potential; Headwater's plans to continue the development of its Marten Hills assets and delineation of the Marten Hills west acreage; the expectation that no fracture stimulations will be required to realize the full potential of the Marten Hills assets; Headwater's plan



to strategically develop its Marten Hills assets through implementation of enhanced oil recovery techniques including waterfloods and potentially polymer floods; Headwater's plans to utilize its free cash flow and working capital surplus to provide financial flexibility for future development and acquisitions; Headwater's expectations of maintaining its strong balance sheet with significant liquidity to enable future internal development opportunities and potential acquisitions; Headwater's belief that fracture stimulation will make undeveloped wells in the McCully Field commercially productive; Headwater's plan to continue to grow its land base by actively participating in future land sales; Headwater's ability to execute its corporate strategy and intention to increase focus on returning excess free cash flow to Shareholders in the future as the Corporation grows; Headwater's intention to test the ERP in 2022 with exercises and drills to ensure its effectiveness and its procedures are revised to ensure it is adhering to the highest industry standards; details of the Corporation's 2022 capital expenditure program; development plans for the assets of the Corporation; land expiries; expected abandonment and reclamation costs; the performance characteristics of oil and natural gas properties; the quantity of reserves; future crude oil, NGLs and natural gas production levels; drilling plans; anticipated future crude oil, natural gas and NGLs prices and currency, exchange and interest rates; 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; Headwater's belief that it is in material compliance with current applicable environmental legislation; Headwater's belief that it is in full compliance with the provisions of applicable tax legislation; 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 and 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 volatility of commodity prices and stock exchanges, risks associated with the Russian Ukrainian conflict, 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, risks associated with public health risks including the 2019 novel coronavirus ("**COVID-19**"), 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 10, 2022 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 further 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.". On May 13, 2021, the articles of the Corporation were amended to increase the maximum number of directors of the Corporation to thirteen directors. The Corporation has no material subsidiaries.

The head office of Headwater is located at 1200, 500 – 4<sup>th</sup> Avenue S.W., Calgary, Alberta T2P 2V6 and its registered office is located at 2400, 525 – 8<sup>th</sup> 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.

### **Year 2021**

#### ***Combined Operations***

Headwater achieved corporate annual average production of 7,393 BOE/d, consisting of 6,665 Bbls/d of heavy crude oil, 4.4 MMcf/d of natural gas and 2 Bbls/d of natural gas liquids.

#### ***Marten Hills Operations***

Headwater spent \$140 million on capital expenditures in the Marten Hills area in 2021 and achieved annual average production of 6,785 BOE/d, consisting of 6,665 Bbls/d heavy crude oil and 0.7 MMcf/d of natural gas. The Corporation drilled 58 (58.0 net) wells including 51 (51.0 net) crude oil wells and 7 (7.0 net) source wells/stratigraphic tests. Headwater achieved first sales gas from its Marten Hills assets in the third quarter of 2021 following commissioning of its joint gas processing facility. In addition, in 2021 Headwater commenced construction of its 15,000 Bbls/d oil processing facility which was commissioned in early March 2022.

### *McCully Operations*

As part of its production optimization strategy, the Corporation shut-in its natural gas production in the McCully Field in New Brunswick in May 2021 and resumed production in late November 2021. Headwater's natural gas production averaged 3.7 MMcf/d and its natural gas liquids production averaged 2 Bbls/d in 2021 from the McCully Field. No development operations occurred as the lifting of the fracking moratorium in the Sussex region remained uncertain.

### *Exercise of Cenovus Warrants*

On December 21, 2021, Headwater announced that it had issued a call notice to Cenovus Marten Hills Partnership ("CMHP"), a wholly-owned subsidiary of Cenovus, requiring CMHP to exercise the 15,000,000 Cenovus Warrants issued to CMHP as partial consideration for Headwater's acquisition of the Acquired Assets under the Cenovus Transaction. CMHP exercised the 15,000,000 Cenovus Warrants to purchase 15,000,000 Common Shares at an exercise price of \$2.00 on December 23, 2021, for total gross proceeds of \$30 million in cash to the Corporation. On exercise of the warrants, Cenovus held approximately 7% of the outstanding Common Shares.

### *Secondary Offering of Common Shares*

On October 14, 2021, Headwater and Cenovus completed a secondary offering (the "**Secondary Offering**") of Common Shares pursuant to a short-form prospectus filed by Headwater. Pursuant to the Secondary Offering, Cenovus, through CMHP, sold 50,000,000 Common Shares through a syndicate of underwriters at a price of \$4.55 per Common Share for total gross proceeds to CMHP of \$227.5 million. The Corporation did not receive any of the proceeds of the Secondary Offering. Cenovus paid the underwriters' fees and all expenses of the Secondary Offering.

Prior to the Secondary Offering, CMHP held 50,000,000 Common Shares, which, at the time, represented approximately 24.7% of the issued and outstanding Common Shares on an undiluted basis and approximately 26.8% of the issued and outstanding Common Shares on a fully diluted basis. Pursuant to the Secondary Offering, CMHP disposed of legal and beneficial ownership of 50,000,000 Common Shares, being 100% of the Common Shares held by CMHP at that time. Following completion of the Secondary Offering, CMHP retained the Cenovus Warrants entitling CMHP to purchase 15,000,000 Common Shares.

As a result of the completion of the Secondary Offering, the Investor Agreement automatically terminated in accordance with its terms as Cenovus no longer held, directly or indirectly, any Common Shares. The Investor Agreement provided CMHP with certain contractual rights related to, among other things, the nomination of directors of the Corporation. In connection with the termination of the Investor Agreement, Sarah Walters, who was a nominee of CMHP on the Board, resigned as a director of the Corporation effective upon completion of the Secondary Offering. Kam Sandhar, who was previously nominated to the Board by CMHP pursuant to the Investor Agreement, remained on the Board notwithstanding the termination of the Investor Agreement.

## **Year 2020**

### *Transaction with Cenovus*

On November 8, 2020, the Corporation entered into a purchase and sale agreement with Cenovus and CMHP, to acquire 100% of Cenovus' assets in the Marten Hills area of Alberta (the "**Acquired Assets**") from CMHP. Pursuant to the agreement, Headwater acquired a 100% working interest in approximately 2,800 barrels per day of heavy oil production and 270 net sections of Clearwater rights (the "**Cenovus Transaction**"). The Cenovus Transaction closed on December 2, 2020. Consideration paid by Headwater for the Acquired Assets consisted of: (i) the issuance to CMHP of 50.0 million Common Shares of the Corporation and 15.0 million Common Share purchase warrants (the "**Cenovus Warrants**") of the Corporation; and (ii) a cash payment of \$32.8 million to CMHP for total consideration of \$135.3 million. Each Cenovus Warrant entitled CMHP to acquire one Common Share at a price of \$2.00 per Common Share for a period of three (3) years. Headwater has the right, after twelve months have elapsed from December 2, 2020 and provided the 20-day volume weighted average trading price of the Common Shares exceeds \$2.00, to require Cenovus to exercise all or a portion of the then-outstanding Cenovus Warrants. See "*General Development of the Business – Year 2021 – Exercise of Cenovus Warrants*" for further details.

At closing of the Cenovus Transaction, CMHP and Headwater entered into an investor agreement (the "**Investor Agreement**"). The Investor Agreement provided CMHP with certain contractual rights related to, among other things, the nomination of directors of the Corporation and the right to participate in equity financings of the Corporation. During the term of the Investor Agreement, CMHP was also required to vote for or otherwise abstain from voting in respect of any management proposal set forth in the management forms of proxy prepared in respect of any meeting of Shareholders. See "*General Development of the Business – Year 2021 – Secondary Offering of Common Shares*" for further details.

Headwater and CMHP also entered into a development agreement (the "**Development Agreement**") and a royalty agreement (the "**Royalty Agreement**") in connection with the Cenovus Transaction. Pursuant to the Development Agreement, Headwater committed to spend \$100 million in capital expenditures on the Acquired Assets by December 31, 2022, unless otherwise extended by CMHP. Pursuant to the Royalty Agreement, Cenovus retained a gross overriding royalty on the lands comprising the Acquired Assets, which was subsequently acquired by Topaz Energy Corp. in May 2021. As at December 31, 2021, Headwater had satisfied the \$100 million capital commitment.

In connection with the Cenovus Transaction and in accordance with the terms of the Investor Agreement, Kam Sandhar and Sarah Walters were appointed to the Board.

### ***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 to 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](http://www.sedar.com).

### ***McCully Operations***

As part of its production optimization strategy, the Corporation shut-in its natural gas production in the McCully Field in New Brunswick in May 2020 and resumed production in late October 2020. Headwater's natural gas production from the McCully Field averaged 3.8 MMcf/d in 2020. No development operations occurred as the lifting of the fracking moratorium in the Sussex region remained uncertain.

### **Year 2019**

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. This 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.

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.

### **Significant Acquisitions**

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

## **DESCRIPTION OF THE BUSINESS**

The Corporation is a Canadian resource company currently engaged in the exploration for, and development and production of, petroleum and natural gas in the Western Canadian Sedimentary Basin and onshore in New Brunswick. With the completion of the Cenovus Transaction in December 2020, Headwater acquired high quality oil production, reserves and lands in the Clearwater play in the Marten Hills area of Alberta. In addition, the Corporation currently has low decline natural gas production and reserves in the McCully Field near Sussex, New Brunswick and a shale gas prospect in New Brunswick.

The Headwater management team is focused on exploration and development in the Marten Hills area as well as potentially expanding its operations to include resource exploration and development in other areas of the Western Canadian Sedimentary Basin. The historic assets of the Corporation in New Brunswick provide production and free cash flow for the Corporation's operations. To the extent that the New Brunswick government's fracking moratorium is lifted in respect of the Corporation's assets in the McCully Field, the Corporation may pursue further development of such assets to supply natural gas to the undersupplied market in Atlantic Canada.

### **Business Strategy**

Headwater's business strategy is to provide attractive long-term shareholder returns by focusing on asset quality and sustainability while maintaining a pristine balance sheet.

Headwater seeks to execute this strategy by:

- ***Building a sustainable core business with no debt.*** Headwater plans to utilize its free cash flow and working capital to provide financial flexibility for future development and acquisitions. Headwater expects to maintain its strong balance sheet with significant liquidity to enable future internal development opportunities and potential acquisitions. As at December 31, 2021, Headwater had working capital of approximately \$90 million and no debt.
- ***Growing the sustainable business through exploitation and evaluation of exploration lands.*** As at March 10, 2022, Headwater has exploration upside with 350 sections of exploration lands. Headwater achieved multiple successful discoveries in 2021 de-risking 43 sections of exploration acreage. The Corporation will continue to test existing and newly acquired exploration lands in 2022.
- ***Adding incremental prospects through strategic land acquisitions.*** The Corporation will continue to grow its land base by actively participating in future land sales.
- ***Implementing secondary recovery where returns justify capital.*** Headwater plans to strategically develop its Marten Hills assets through implementation of enhanced oil recovery techniques, including waterfloods. Three of the Corporation's crude oil wells were converted to water injection wells in 2021.

- ***Pursuing mergers and acquisitions that create incremental long term shareholder value.*** Headwater strives to actively pursue strategic acquisitions with synergistic characteristics such as existing long life producing assets or opportunities with significant, low risk upside potential.
- ***Implementing a return of capital strategy at the appropriate time.*** As the Corporation evolves with rapid growth and execution of its corporate strategy, there will be an increased focus on returning excess free cash flow to shareholders in the future.

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; evaluate and complete acquisitions of assets; 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 operations 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, 2021, the Corporation had 22 employees and 4 consultants in the Calgary head office, 1 employee in Halifax, 3 employees in the field in New Brunswick, 7 consultants in the field in Marten Hills and 1 consultant in the field in New Brunswick.

### **Marketing**

Headwater's heavy crude production in the Marten Hills area is sold through various creditworthy counterparties at current market prices. In connection with the Cenovus Transaction, Headwater and Cenovus entered into a marketing agreement. Headwater considers the marketing agreement to be at market terms and in the ordinary course of business. The marketing agreement terminates on December 2, 2023. The Corporation has various take or pay pipeline service agreements to deliver its production from the Marten Hills area to market that expire in 2031. For details of the Corporation's transportation agreements in place as at December 31, 2021, see the Corporation's audited financial statements for the year ended December 31, 2021, which have been filed on SEDAR and may be viewed under the Corporation's profile at [www.sedar.com](http://www.sedar.com). Headwater sells its natural gas production from the Marten Hills area through a marketing agreement with a creditworthy counterparty which is at market terms and in the ordinary course of business.

A key component of the Corporation's production optimization strategy related to its McCully assets 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, 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.

The Corporation 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. 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 in recent years also began selling natural gas 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 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 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, 2021 and subsequent to December 31, 2021, see the Corporation's audited financial statements for the year ended December 31, 2021, which have been filed on SEDAR and may be viewed under the Corporation's profile at [www.sedar.com](http://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 oil and natural gas production. Oil and natural gas prices have fluctuated widely recently 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. In addition, the actions of OPEC+ and other oil producing countries and other factors impacting supply of oil will impact the price of oil. Weather and general economic conditions, as well as conditions in other oil and natural gas regions, also impact supply and demand of commodity prices and costs. Any decline in oil and 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.

The Corporation produces natural gas from the McCully Field in New Brunswick, 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. As a result, the Corporation shut-in its production from the McCully Field in the summer months and only produces in the winter months when the prices are higher.

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. In anticipation of the operational delays associated with "spring break up", the Corporation takes certain steps to mitigate interruption to its activities including, scheduling drilling and completion activities to be completed well before the spring break up season and setting up extra storage where possible to mitigate downtime. Through the duration of spring break up, drilling and exploratory activities slow and the Corporation's production which is not otherwise tied-in may be shut-in temporarily if access is limited.

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

See "*Risk Factors – Prices, Markets and Marketing*", "*Risk Factors – Seasonality*" and "*Risk Factors – Climate Change*".

### **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 at December 31, 2021, Headwater's LMR was 38 in Alberta significantly exceeding the Alberta industry LMR average.

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. 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 expected to have a material effect on the Corporation's financial results. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*".

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 2021, 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 Corporation's 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.

Headwater has a corporate Environment Management System which is continuously updated and meets 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 Corporation's 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 potential adverse environmental effects. Management intends to test the ERP in 2022 with exercises and drills 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 10, 2022. The effective date of the Reserves Data is December 31, 2021 and the preparation date of the Reserves Data is February 10, 2022.

### **Disclosure of Reserves Data**

The Reserves Data set forth below is based upon the evaluation by GLJ with an effective date of December 31, 2021, contained in the GLJ Report. The Reserves Data summarizes the NGLs, conventional natural gas, shale gas and heavy crude oil 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, conventional natural gas, shale gas and heavy crude oil reserves and the net present value of future net revenue attributable to such reserves as evaluated in the GLJ Report based on forecast price and cost assumptions. The NGLs, conventional natural gas, shale gas and heavy crude oil reserve estimates presented in the GLJ 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 under the heading "*Notes on Reserves Data and Other Oil and Gas Information*" in 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, conventional natural gas, shale gas and heavy crude oil 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, conventional natural gas, shale gas and heavy crude oil reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual NGLs, conventional natural gas, shale gas and heavy crude oil reserves may be greater than or less than the estimates provided herein. In general, estimates of economically recoverable NGLs, conventional natural gas, shale gas and heavy crude oil 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, conventional natural gas, shale gas, heavy crude oil, 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, conventional natural gas, shale gas and heavy crude oil 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.

Headwater's reserves are located in the Marten Hills area of Alberta, Canada and in the McCully Field in New Brunswick, Canada. 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, 2021 FORECAST PRICES AND COSTS

Reserve Category	Conventional Natural Gas		Shale Natural Gas		Heavy Crude Oil		Natural Gas Liquids		Total Oil Equivalent	
	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)	Gross (MBbl)	Net (MBbl)	Gross (MBbl)	Net (MBbl)	Gross (MBOE)	Net (MBOE)
<b>PROVED</b>										
Developed Producing	18,229	17,462	810	793	6,439	4,948	206	150	9,818	8,140
Developed Non-Producing	-	-	994	972	-	-	-	-	166	162
Undeveloped	1,995	1,738	-	-	5,226	4,303	121	92	5,680	4,685
<b>TOTAL PROVED</b>	<b>20,224</b>	<b>19,200</b>	<b>1,804</b>	<b>1,765</b>	<b>11,665</b>	<b>9,251</b>	<b>327</b>	<b>242</b>	<b>15,663</b>	<b>12,987</b>
<b>PROBABLE</b>										
Developed Producing	5,814	5,490	227	222	3,543	2,685	111	79	4,661	3,716
Developed Non-Producing	-	-	281	275	-	-	-	-	47	46
Undeveloped	1,168	1,008	-	-	3,154	2,451	71	49	3,420	2,668
<b>TOTAL PROBABLE</b>	<b>6,983</b>	<b>6,498</b>	<b>507</b>	<b>496</b>	<b>6,697</b>	<b>5,136</b>	<b>182</b>	<b>128</b>	<b>8,127</b>	<b>6,430</b>
<b>TOTAL PROVED PLUS PROBABLE</b>	<b>27,206</b>	<b>25,697</b>	<b>2,311</b>	<b>2,261</b>	<b>18,362</b>	<b>14,387</b>	<b>509</b>	<b>370</b>	<b>23,790</b>	<b>19,417</b>

Note:

- (1) Columns may not add due to rounding.

#### SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE as at December 31, 2021 FORECAST PRICES AND COSTS<sup>(1)</sup>

RESERVES CATEGORY	Before Income Tax Discounted at (%/year)					After Income Taxes Discounted at (%/year) <sup>(2)</sup>				
	0 (\$000s)	5 (\$000s)	10 (\$000s)	15 (\$000s)	20 (\$000s)	0 (\$000s)	5 (\$000s)	10 (\$000s)	15 (\$000s)	20 (\$000s)
<b>PROVED</b>										
Developed Producing	330,844	309,567	288,497	270,537	255,468	306,069	286,707	267,285	250,754	236,934
Developed Non-Producing	1,065	1,030	961	880	801	699	706	670	618	563
Undeveloped	148,348	128,751	112,297	98,450	86,739	111,565	95,912	82,718	71,601	62,201
<b>TOTAL PROVED</b>	<b>480,258</b>	<b>439,349</b>	<b>401,755</b>	<b>369,867</b>	<b>343,008</b>	<b>418,332</b>	<b>383,324</b>	<b>350,673</b>	<b>322,973</b>	<b>299,698</b>
<b>PROBABLE</b>										
Developed Producing	152,176	122,256	100,917	85,581	74,106	121,061	96,463	79,055	66,704	57,549
Developed Non-Producing	318	261	213	173	141	287	211	159	122	95
Undeveloped	130,209	108,300	91,744	79,092	69,262	100,629	83,657	70,729	60,823	53,123
<b>TOTAL PROBABLE</b>	<b>282,703</b>	<b>230,817</b>	<b>192,873</b>	<b>164,846</b>	<b>143,509</b>	<b>221,976</b>	<b>180,331</b>	<b>149,943</b>	<b>127,648</b>	<b>110,767</b>
<b>TOTAL PROVED PLUS PROBABLE</b>	<b>762,961</b>	<b>670,166</b>	<b>594,628</b>	<b>534,713</b>	<b>486,517</b>	<b>640,309</b>	<b>563,655</b>	<b>500,616</b>	<b>450,621</b>	<b>410,465</b>

Notes:

- (1) The estimated values of future net revenues disclosed do not represent fair market value.  
(2) Based on Headwater's estimated tax pools as at December 31, 2021. The after-tax net present value of Headwater's oil and natural gas properties reflects the income tax burden on the properties on a stand-alone basis and takes into account Headwater's existing tax pools. It does not consider tax planning.

**TOTAL FUTURE NET REVENUE  
(UNDISCOUNTED)  
as at December 31, 2021  
FORECAST PRICES AND COSTS<sup>(1)</sup>**

<b>RESERVES CATEGORY</b>	<b>REVENUE (\$000s)</b>	<b>ROYALTIES (\$000s)</b>	<b>OPERATING COSTS (\$000s)</b>	<b>DEVELOP- MENT COSTS (\$000s)</b>	<b>ABANDONMENT AND RECLAMATION COSTS<sup>(2)</sup> (\$000s)</b>	<b>FUTURE NET REVENUE BEFORE INCOME TAXES (\$000s)</b>	<b>FUTURE INCOME TAXES (\$000s)</b>	<b>FUTURE NET REVENUE AFTER INCOME TAXES (\$000s)</b>
Proved Reserves	945,879	165,919	169,016	88,616	42,069	480,258	61,926	418,332
Proved Plus Probable Reserves	1,444,688	271,506	269,585	94,329	46,306	762,961	122,652	640,309

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, 2021  
FORECAST PRICES AND COSTS**

<b>RESERVES CATEGORY</b>	<b>PRODUCTION TYPE</b>	<b>FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (\$000's)<sup>(2)</sup></b>	<b>UNIT VALUE<sup>(3)</sup> (\$)/BOE</b>
Proved Reserves	Conventional Natural Gas <sup>(1)</sup>	63,304	23.97
	Shale Gas <sup>(1)</sup>	2,128	16.01
	Heavy Crude Oil <sup>(1)</sup>	336,323	32.93
	<b>Total<sup>(2)</sup></b>	<b>401,755</b>	<b>30.93</b>
Proved Plus Probable Reserves	Conventional Natural Gas <sup>(1)</sup>	73,702	21.98
	Shale Gas <sup>(1)</sup>	2,459	14.46
	Heavy Crude Oil <sup>(1)</sup>	518,467	32.62
	<b>Total<sup>(2)</sup></b>	<b>594,628</b>	<b>30.62</b>

Notes:

- (1) Including by-products (including NGLs). The GLJ 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, 2021, 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, 2022.

**SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS<sup>(1)</sup>**  
**as of December 31, 2021**  
**FORECAST PRICES AND COSTS**

Year	Crude Oil				Edmonton Liquids Prices	
	WTI Cushing Oklahoma (US\$/Bbl)	Light Sweet Crude Oil at Edmonton 40° API (Cdn\$/Bbl)	Bow River Crude Oil at Hardisty (Cdn\$/Bbl)	WCS Crude Oil at Hardisty (Cdn\$/Bbl)	Pentanes Plus Edmonton (Cdn\$/Bbl)	Butanes Price Edmonton (Cdn\$/Bbl)
Forecast <sup>(4)</sup>						
2022	72.83	86.82	75.22	74.43	91.85	57.49
2023	68.78	80.73	69.92	69.17	85.53	50.17
2024	66.76	78.01	67.26	66.54	82.98	48.53
2025	68.09	79.57	68.60	67.87	84.63	49.50
2026	69.45	81.16	69.98	69.23	86.33	50.49
2027	70.84	82.78	71.37	70.61	88.05	51.50
2028	72.26	84.44	72.80	72.02	89.82	52.53
2029	73.70	86.13	74.25	73.46	91.61	53.58
2030	75.18	87.85	75.49	74.69	93.44	54.65
2031	76.68	89.60	77.00	76.19	95.32	55.74
2032	78.21	91.40	78.54	77.71	97.22	56.86

Thereafter escalation rate of 2.0%

Year	Natural Gas					
	Natural Gas AECO-C Spot (Cdn\$/MMBtu)	NYMEX Henry Hub (US\$/MMBTU)	AGT Gas Price (US\$/MMBtu)	McCully Gas Price <sup>(2)</sup> (Cdn\$/Mcf)	Inflation Rate %/Year	Exchange Rate <sup>(3)</sup> (US\$/Cdn\$)
Forecast <sup>(4)</sup>						
2022	3.56	3.85	7.55	13.84	0.0	0.797
2023	3.20	3.44	5.64	10.19	2.3	0.797
2024	3.05	3.17	4.37	6.93	2.0	0.797
2025	3.10	3.24	4.46	6.91	2.0	0.797
2026	3.17	3.30	4.55	6.87	2.0	0.797
2027	3.23	3.37	4.64	6.76	2.0	0.797
2028	3.30	3.44	4.74	6.90	2.0	0.797
2029	3.36	3.51	4.84	7.05	2.0	0.797
2030	3.43	3.57	4.92	7.37	2.0	0.797
2031	3.50	3.65	5.00	7.53	2.0	0.797
2032	3.57	3.72	5.08	7.78	2.0	0.797

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 from the McCully Field. 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. The McCully gas price in years 2022 – 2023 reflects only the winter producing months (January to April and November to December) to correlate to the intermittent production strategy employed by the Corporation to capture seasonal premium pricing. After 2023, the GLJ Report assumes Headwater produces volumes from its reserves continuously over the year and as such, McCully pricing reflects the full year.
- (3) The exchange rate used to generate the benchmark reference prices in this table.
- (4) As at December 31, 2021.

The weighted average historical prices realized, before financial derivative contracts, by the Corporation for the year ended December 31, 2021, were \$7.18/Mcf for natural gas, \$70.14/Bbl for NGLs and \$73.39/Bbl for heavy crude oil. The weighted average historical price of heavy crude oil net of costs to blend was \$68.69/Bbl.

### Reconciliation of Changes in Reserves

The following table sets out the reconciliation of the gross reserves of the Corporation as at December 31, 2021 as compared to December 31, 2020:

Reserves Reconciliation of Corporation Total Reserves By Principal Product Type (Forecast Prices and Costs)									
FACTORS	Conventional Natural Gas			Shale Natural Gas			Heavy Crude Oil		
	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (MBbl)	Gross Probable (MBbl)	Gross Proved Plus Probable (MBbl)
<b>December 31, 2020<sup>(1)</sup></b>	<b>19,157</b>	<b>5,712</b>	<b>24,869</b>	<b>1,820</b>	<b>524</b>	<b>2,344</b>	<b>5,854</b>	<b>2,478</b>	<b>8,332</b>
Extensions and Improved Recovery <sup>(3)</sup>	2,660	1,587	4,247	-	-	-	7,407	4,304	11,711
Technical Revisions <sup>(4)</sup>	(202)	(396)	(597)	3	(21)	(18)	793	(142)	650
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	158	79	238	20	4	24	44	57	101
Production	(1,550)	-	(1,550)	(39)	-	(39)	(2,433)	-	(2,433)
<b>December 31, 2021<sup>(2)</sup></b>	<b>20,224</b>	<b>6,983</b>	<b>27,206</b>	<b>1,804</b>	<b>507</b>	<b>2,311</b>	<b>11,665</b>	<b>6,697</b>	<b>18,362</b>

Reserves Reconciliation of Corporation Reserves By Principal Product Type (Forecast Prices and Costs)						
FACTORS	Natural Gas Liquids			Total Oil Equivalent		
	Gross Proved (MBOE)	Gross Probable (MBOE)	Gross Proved Plus Probable (MBOE)	Gross Proved (MBOE)	Gross Probable (MBOE)	Gross Proved Plus Probable (MBOE)
<b>December 31, 2020<sup>(1)</sup></b>	<b>146</b>	<b>66</b>	<b>212</b>	<b>9,496</b>	<b>3,583</b>	<b>13,080</b>
Extensions and Improved Recovery <sup>(3)</sup>	163	97	260	8,013	4,665	12,679
Technical Revisions <sup>(4)</sup>	19	19	38	778	(193)	586
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	74	71	145
Production	(1)	-	(1)	(2,698)	-	(2,698)
<b>December 31, 2021<sup>(2)</sup></b>	<b>327</b>	<b>182</b>	<b>509</b>	<b>15,663</b>	<b>8,127</b>	<b>23,790</b>

Notes:

- (1) As evaluated by GLJ as at December 31, 2020, using the average of the forecasts by GLJ, McDaniel & Associates Ltd. and Sproule Associates Limited and costs as at such date.
- (2) As evaluated in the GLJ Report.
- (3) Extensions are additional reserves due to the increase in the 2021 capital expenditure program. Improved recovery is a result of additional waterflood reserves.
- (4) Technical revisions include all changes in reserves due to well performance.
- (5) Columns may not add due to rounding.

### Additional Information Relating to Reserves Data

#### Undeveloped Reserves

The following tables set forth the proved undeveloped reserves and the probable undeveloped reserves, each by product type, attributed to the Corporation's assets for the years ended December 31, 2021, 2020 and 2019 and also the remaining cumulative proved undeveloped reserves and the probable undeveloped reserves as at the end of such years.

Proved Undeveloped Reserves

Year	Conventional Natural Gas (MMcf)		Shale Natural Gas (MMcf)		Heavy Crude Oil (MBbl)		Natural Gas Liquids (MBbl)		Oil Equivalent (MBOE)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2019	-	-	-	-	-	-	-	-	-	-
2020	3,099	3,099	-	-	3,673	3,673	128	128	4,317	4,317
2021	<b>1,765</b>	<b>1,995</b>	-	-	<b>4,721</b>	<b>5,226</b>	<b>107</b>	<b>121</b>	<b>5,123</b>	<b>5,680</b>

Notes:

- (1) "First Attributed" refers to reserves first attributed at the year end of the corresponding fiscal year.
- (2) Columns may not add due to rounding.
- (3) The Corporation did not have proved undeveloped reserves in 2019.

Probable Undeveloped Reserves

Year	Conventional Natural Gas (MMcf)		Shale Natural Gas (MMcf)		Heavy Crude Oil (Mbbbl)		Natural Gas Liquids (Mbbbl)		Oil Equivalent (MBOE)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2019	-	-	-	-	-	-	-	-	-	-
2020	1,507	1,507	-	-	1,637	1,637	62	62	1,950	1,950
2021	<b>1,073</b>	<b>1,168</b>	-	-	<b>2,958</b>	<b>3,154</b>	<b>65</b>	<b>71</b>	<b>3,202</b>	<b>3,420</b>

Notes:

- (1) "First Attributed" refers to reserves first attributed at the year end of the corresponding fiscal year.
- (2) Columns may not add due to rounding.
- (3) The Corporation did not have any probable undeveloped reserves in 2019.

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.

The Corporation attributed certain proved and probable undeveloped reserves to the Marten Hills area. The Corporation plans to develop all of its proved and probable undeveloped reserves within two years; however, these locations will continue to be re-evaluated to assess their relative economic merits when compared to other projects available to the Corporation. Undeveloped reserves planned to be developed beyond two years are scheduled in that manner due to various factors including access to capital, limitations on egress and pricing uncertainty.

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 becomes available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, 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 in New Brunswick requiring hydraulic fracturing no longer meet the necessary conditions to qualify as reserves. See "*Risk Factors – Hydraulic Fracturing*", "*Risk Factors – Exploration, Development and Production Risks*" and other factors noted in "*Risk Factors*".

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

The Corporation's total future abandonment and site reclamation costs are based on information published by the AER with respect to AER Licensee Liability Management Program in Alberta (in respect of the Corporation's Alberta assets) and 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. GLJ has determined that Headwater's estimates of its abandonment and reclamation costs are reasonable and have included these costs in the GLJ Report. All costs associated with the process of restoring the Corporation's properties that have been disturbed by oil and gas activities to a standard imposed by applicable government or regulatory authorities have been deducted for the purposes of calculating the net present value of the future net revenue associated with the Corporation's reserves.

Headwater estimates that the total cost to abandon and reclaim all wells with reserves, wells with no attributed reserves and related facilities as of December 31, 2021, is approximately \$26.4 million on an undiscounted, uninflated basis. The abandonment and reclamation costs in the McCully Field in New Brunswick include 32.5 net wells, the gas processing plant and transmission pipeline and in the Marten Hills area of Alberta the estimate includes 85.0 net wells (76.0 net oil and gas wells and 9.0 net observation/water source/stratigraphic test wells), related multi-well battery infrastructure, the joint natural gas processing facility and the oil processing facility.

The GLJ Report included the full estimated undiscounted future abandonment and reclamation costs, plus all forecast estimates of abandonment and reclamation costs attributable to future development activity associated with the reserves.

Of the undiscounted future abandonment and reclamation costs to be incurred over the life of Headwater's proved plus probable reserves, approximately \$46.3 million (undiscounted) has been deducted in estimating the future net revenue in the GLJ Report, which represents the Corporation's total existing estimated abandonment and reclamation costs,

plus all forecast estimates of abandonment and reclamation costs attributable to future development activity associated with the reserves.

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, 2021 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](http://www.sedar.com).

### ***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.

<b>Year</b>	<b>Forecast Prices and Costs</b>	
	<b>Proved Reserves (\$M)</b>	<b>Proved Plus Probable Reserves (\$M)</b>
2022	66,150	70,350
2023	19,806	21,211
2024	-	-
2025	-	-
2026	-	-
Thereafter	2,661	2,768
Total: Undiscounted	<b>88,616</b>	<b>94,329</b>
Discounted 10%	<b>81,863</b>	<b>86,873</b>

The future development costs for both proved and proved plus probable reserves are expected to be funded through future cash flow provided by operating activities and from the Corporation's existing working capital. Headwater's anticipated capital expenditures in 2022 include anticipated costs for exploration and development activities in the Marten Hills area of \$145 million which is in excess of the future development costs utilized for estimating the future net revenue of both the Corporation's proved and proved plus probable reserves as set out in the GLJ Report. The 2022 capital expenditure budget includes expenditures for development drilling, exploration drilling, infrastructure and land costs that are not contained in the GLJ Report. Headwater's capital program does not include any new acquisition opportunities, which would likely be financed through existing working capital or debt or equity financings, if necessary. Headwater may also consider issuing Common Shares or other securities as consideration for future acquisitions.

Headwater's 2022 capital expenditure program includes insignificant capital spending in New Brunswick due to the hydraulic fracturing moratorium currently in effect in New Brunswick. Future development capital after 2023 is associated with McCully gas plant optimization.

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 GLJ Report. Failure to develop those reserves may have a negative impact on Headwater's 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, conventional natural gas, shale gas and heavy crude oil assets uneconomic.

Factors that could result in the change in timing or cancelled future developments include, but are not limited to, changing economic and technical conditions, surface access issues, the availability of services and access to pipeline or processing facilities.



See "Statement of Reserves Data and Other Oil and Gas Information – Description of Principal Properties" for a description of the Corporation's exploration and development plans and expenditures.

## **Other Oil and Gas Information**

### ***Description of Principal Properties***

#### ***Marten Hills, Alberta***

The Marten Hills area is located approximately 250 kilometres north of Edmonton, Alberta and targets conventional heavy oil from the Clearwater formation. As at December 31, 2021, the Corporation's interests in the Marten Hills area consisted of approximately 208,223 net acres, including approximately 182,702 acres or 285 net sections of Clearwater rights.

The Clearwater formation is characterized as a conventional reservoir, with variability throughout, but in general is an oil-bearing formation of approximately 15 meters in thickness. The Clearwater formation's reservoir characteristics provide for development under the application of open-hole multi-lateral wells targeted at a vertical depth of approximately 500 to 800 meters. There is also the potential for waterfloods and polymer floods to augment the resource, increasing recovery potential.

The Corporation's heavy oil production (average 18 - 22° API) must be blended with diluent during the winter months to reduce the viscosity of the heavy oil to meet downstream pipeline specifications. The annual average production from the Corporation's Marten Hill assets in 2021 was 6,785 BOE/d (6,665 Bbls/d of heavy crude oil and 722 Mcf/d of natural gas). Fourth quarter 2021 production from the Corporation's Marten Hill assets was 9,803 BOE/d (9,377 Bbls/d of heavy crude oil and 2,557 Mcf/d of natural gas). The Corporation's realized price received for its heavy crude oil is determined by the quality of the crude compared to the benchmark reference price of WCS.

As at December 31, 2021, Headwater's Marten Hill assets included 73.0 net producing oil wells, 2.0 net non-producing oil wells, 1.0 net non-producing natural gas well, 9.0 net observation/water source/stratigraphic test wells, 8 multi-well batteries, a joint gas processing facility and an oil processing facility. Headwater spent an aggregate of \$140 million on capital expenditures in Marten Hills in 2021 including \$65 million on drilling and completions, \$62 million on equipping and facilities, \$11 million on road construction and site preparation and \$2 million on lease acquisition and geological and geophysical costs. In 2021, the Corporation drilled 58 (58.0 net) wells including 51 (51.0 net) crude oil wells and 7 (7.0 net) source wells/stratigraphic tests. Out of the 58 net wells drilled in year, Headwater converted 3 wells into injection wells to commence its waterflood program.

In connection with the completion of the Cenovus Transaction, Headwater assumed certain transportation commitments from CMHP. These transportation commitments are long-term in nature, intended to secure the Corporation market access for its heavy oil production. For details of the Corporation's transportation commitments, see the Corporation's audited financial statements for the year ended December 31, 2021, which have been filed on SEDAR and may be viewed under the Corporation's profile at [www.sedar.com](http://www.sedar.com). Pursuant to the Royalty Agreement, Cenovus retained a gross overriding royalty on the lands comprising the Acquired Assets. In 2021, Cenovus sold its interest in the Royalty Agreement to Topaz Energy Corp.

The GLJ Report assigned gross proved plus probable reserves of 18,362 MMBbl of heavy oil, 8,034 MMcf of conventional natural gas and 489 MBbl of natural gas liquids within the Marten Hills area as at December 31, 2021.

The Corporation's Marten Hill assets are also characterized by positive environmental, social and governance attributes including minimal abandonment and reclamation liability, reduced freshwater usage as no hydraulic fracture stimulation is required and a decreased environmental footprint due to pipeline connected multi-well pad development. The joint gas processing facility built in 2021 allows Headwater to achieve gas conservation from all production in the core development area of Marten Hills.

### ***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 Corporation's interests in the McCully Field consist of the following petroleum and natural gas leases:

- 100% working interest in lease number 06-01 (40,930 acres).
- 50% working interest in lease number 06-02 (3,561 gross acres and 1,780 net acres).
- 50% working interest in lease number 09-01 (36,531 gross acres and 18,265 net acres held jointly with Nutrien).
- 100% working interest in lease number 13-02C (135,920 gross acres).

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 in recent years the Corporation has also been selling natural gas 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'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 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.

### ***Oil and Gas Wells***

The following table sets forth the number and status of wells as at December 31, 2021 in which Headwater has a working interest. All of the wells in which Headwater has an interest are located in the Province of Alberta and onshore in the Province of New Brunswick.

	<b>Oil Wells</b>				<b>Natural Gas Wells</b>			
	<b>Producing</b>		<b>Non-Producing</b>		<b>Producing</b>		<b>Non-Producing</b>	
	<b>Gross</b>	<b>Net</b>	<b>Gross</b>	<b>Net</b>	<b>Gross</b>	<b>Net</b>	<b>Gross</b>	<b>Net</b>
New Brunswick	-	-	1.0	1.0	32.0	24.5	8.0	7.0
Alberta	73.0	73.0	2.0	2.0	-	-	1.0	1.0
<b>Total</b>	<b>73.0</b>	<b>73.0</b>	<b>3.0</b>	<b>3.0</b>	<b>32.0</b>	<b>24.5</b>	<b>9.0</b>	<b>8.0</b>

Note:

- (1) Excludes abandoned, water source and stratigraphic test wells.

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

The following table sets out the developed and undeveloped land holdings of Headwater as at December 31, 2021.

	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
Saskatchewan	14,872	14,872	-	-	14,872	14,872
Alberta	199,103	199,103	9,120	9,120	208,223	208,223
<b>Total</b>	<b>423,798</b>	<b>405,531</b>	<b>16,238</b>	<b>14,458</b>	<b>440,036</b>	<b>419,989</b>

Headwater surrendered approximately 123,550 net acres of undeveloped land in the Old Harry prospect in the Laurentian Channel in Québec in February 2021 and 640 net acres of undeveloped land in Alberta in July 2021.

No rights to explore, develop and exploit the Corporation's undeveloped land holdings are expected to expire before December 31, 2022.

### **Forward Contracts**

Headwater's operational results and financial condition will be dependent upon the prices received for its heavy crude oil, NGLs, conventional natural gas and shale gas production. Heavy crude oil, NGLs, conventional natural gas and shale gas prices have fluctuated widely in recent years. Any upward or downward movement in heavy crude oil, NGLs, conventional 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 in Canada*".

Additionally, the Corporation is exposed to fluctuations of the Canadian to U.S. dollar exchange rate given realized pricing is directly influenced by U.S. dollar denominated benchmark pricing and from exposure to its U.S. dollar denominated heavy oil, natural gas and natural gas liquids marketing arrangements. See "*Risk Factors – Variations in Foreign Exchange Rates and Interest Rates*".

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 financial statements for the year ended December 31, 2021, which have been filed on SEDAR and may be viewed under the Corporation's profile at www.sedar.com. See "*Risk Factors – Hedging*".

### **Tax Horizon**

Headwater has approximately \$283 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, CEC and non-capital losses. No cash income taxes were recorded for the year ended December 31, 2021. Based upon Headwater's planned capital expenditures and various other assumptions, Headwater expects to be taxable in 2022. The level of capital expenditures, future commodity pricing and additional acquisitions completed by the Corporation, as well as a variety of other factors, impact the Corporation's tax horizon. Additional spending could extend the Corporation's tax horizon. For more information, please see Note 13 "*Income Taxes*" in Corporation's audited financial statements for the year ended December 31, 2021, available on Headwater's website at www.headwaterexp.com and on SEDAR at www.sedar.com.

### **Exploration and Development Activities**

Headwater incurred minimal capital expenditures related to exploration or development activities in New Brunswick during the year ended December 31, 2021, and does not have any plans to conduct significant exploration and development activities in New Brunswick until the moratorium on hydraulic fracturing in New Brunswick is lifted.

Headwater incurred exploration and development expenditures of approximately \$140 million in the Marten Hills area of Alberta during the year ended December 31, 2021. See "*Statement of Reserves Data and Other Oil and Gas Information – Description of Principal Properties*".

On November 10, 2021, the Board approved a 2022 capital budget of \$120 million. The capital budget includes approximately \$78 million directed towards the continued development of the Marten Hills core area and approximately \$42 million to continued delineation and development of the Marten Hills west acreage. The capital budget is expected to result in 2022 annual average production of 12,500 BOE/d (11,500 Bbls/d of heavy crude oil and 6.2 MMcf/d of natural gas) with fourth quarter 2022 average production expected to be 15,000 BOE/d (13,770 Bbls/d of heavy crude oil and 7.4 MMcf/d of natural gas). On February 1, 2022, the Board approved an increase to the 2022 capital budget from \$120 million to \$145 million to allow for drilling on newly acquired exploration prospects. The resulting increase in capital is expected to have a nominal increase on 2022 production. See "*Statement of Reserves Data and Other Oil and Gas Information – Description of Principal Properties*".

### **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, 2021:

<u>(\$ thousands)</u>	<u>December 31, 2021</u>
Property Acquisition	
<i>Proved Properties</i>	-
<i>Unproved Properties</i>	1,721
Exploration Costs	12,688
Development Costs	125,112
Dispositions	-
Total capital expenditures	<u>139,521</u>

Note:

- (1) Includes seismic costs and costs associated with drilling, completing and equipping the Corporation's exploration wells.

### **Production Estimates**

The following table sets out the volume of working interest production estimated for the year ended December 31, 2022, 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*".

	<u>Conventional Natural Gas</u>	<u>Shale Natural Gas</u>	<u>Heavy Crude Oil</u>	<u>Natural Gas Liquids</u>	<u>Total</u>
	<u>(Mcf/d)</u>	<u>(Mcf/d)</u>	<u>(Bbls/d)</u>	<u>(Bbls/d)</u>	<u>(BOE/d)</u>
Proved					
Developed Producing	6,693	105	8,006	212	9,351
Developed Non- Producing	-	224	-	-	37
Undeveloped	411	-	2,148	25	2,242
Total Proved	7,104	329	10,154	237	11,630
Total Probable	398	2	1,555	20	1,642
Total Proved Plus Probable	<u>7,503</u>	<u>331</u>	<u>11,710</u>	<u>257</u>	<u>13,272</u>

The gross production estimated for the year ended December 31, 2022, reflected in the estimate of future net revenue for the Corporation's gross P+P Reserves from the Marten Hills area of Alberta is 11,710 Bbls/d of heavy crude oil, 4,166 Mcf/d of natural gas and 254 Bbls/d of natural gas liquids. The gross production estimated for the year ended December 31, 2022, reflected in the estimate of future net revenue for the Corporation's gross P+P Reserves from the

McCully Field in New Brunswick is 3,337 Mcf/d of conventional natural gas, 331 Mcf/d of shale natural gas and 3 Bbls/d of NGLs.

### ***Production History***

The following table summarizes certain information in respect of the Corporation's production, prices received, royalties paid, production costs, transportation costs and resulting netback for the periods indicated below.

	Quarter Ended 2021				Year Ended
	Mar. 31	June 30	Sept. 30	Dec. 31	Dec. 31, 2021
<b>Average Daily Production<sup>(1)</sup></b>					
Natural Gas (MMcf/d)	8.5	2.3	0.3	6.4	4.4
NGLs (bbls/d)	5	5	-	-	2
Heavy Crude Oil (bbls/d)	3,385	6,185	7,637	9,377	6,665
Combined (BOE/d)	4,805	6,565	7,688	10,449	7,393
<b>Average Net Sales Prices Received<sup>(2)</sup></b>					
Natural Gas (\$/Mcf)	7.48	2.76	4.49	8.46	7.18
NGLs (\$/bbl)	66.55	73.99	-	-	70.14
Heavy Crude Oil (\$/bbl)	55.72	64.20	70.00	75.12	68.69
Combined (\$/BOE)	52.51	61.52	69.71	72.62	66.18
<b>Royalties Paid<sup>(4)</sup></b>					
Natural Gas (\$/Mcf)	0.29	0.08	0.69	0.45	0.33
Natural gas liquids (\$/bbl)	-	-	-	-	-
Heavy Crude Oil (\$/bbl)	7.08	9.35	10.50	12.32	10.45
Combined (\$/BOE)	5.49	8.84	10.46	11.34	9.62
<b>Production Costs<sup>(3)(4)</sup></b>					
Natural Gas (\$/Mcf)	0.74	1.54	13.99	1.26	1.28
Natural gas liquids (\$/bbl)	-	-	-	-	-
Heavy Crude Oil (\$/bbl)	6.13	4.63	3.89	3.81	4.31
Combined (\$/BOE)	5.62	4.89	4.42	4.20	4.64
<b>Transportation Costs<sup>(4)</sup></b>					
Natural Gas (\$/Mcf)	-	-	0.78	-	0.01
Natural gas liquids (\$/bbl)	-	-	-	-	-
Heavy Crude Oil (\$/bbl)	8.60	8.70	8.71	7.78	8.36
Combined (\$/BOE)	6.04	8.21	8.68	6.98	7.55
<b>Netback<sup>(5)</sup></b>					
Natural Gas (\$/Mcf)	6.45	1.14	(10.97)	6.75	5.56
Natural gas liquids (\$/bbl)	66.55	73.99	-	-	70.14
Heavy Crude Oil (\$/bbl)	33.91	41.52	46.90	51.21	45.57
Combined (\$/BOE)	35.36	39.58	46.15	50.10	44.37

Notes:

- (1) Before deduction of royalties.
- (2) Sales prices are before hedging, net of costs to blend and do not include revenue from gathering, processing and transportation.
- (3) This figure includes all field production expenses.
- (4) Headwater did not record royalties, production costs and transportation costs for NGLs as Headwater only had nominal sales of NGLs in 2021 and therefore information is included in the combined BOE.
- (5) Calculated using average sales volumes in the period.

In 2021, the principal property that the Corporation derived most of its production from the Marten Hills area in Alberta. The gross working interest production from Marten Hills in 2021 was 6,665 Bbls/d of heavy oil and 722 Mcf/d of natural gas. The McCully Field contributed 3.7 MMcf/d of natural gas and 2 Bbls/d of NGLs to the Corporation's total production in 2021.

## 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)
Brad Christman Alberta, Canada	Vice President, Production (since April 1, 2020)
Chandra Henry <sup>(1)(2)</sup> , CPA, CFA, ICD.D Alberta, Canada	Director (since March 4, 2020)
Phillip Knoll <sup>(3)</sup> , P.Eng Alberta, Canada	Director (since September 21, 2010)
Stephen Larke <sup>(2)</sup> , B. Comm, CFA, ICD.D Alberta, Canada	Director (since March 4, 2020)
Kevin Olson <sup>(1)(3)</sup> Alberta, Canada	Lead Independent Director (since March 4, 2020)
David Pearce <sup>(2)(3)</sup> Alberta, Canada	Director (since March 4, 2020)
Kam Sandhar <sup>(1)</sup> Alberta, Canada	Director (since December 2, 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 10, 2022, the directors and executive officers of Headwater, as a group, beneficially owned or controlled or directed, directly or indirectly, 11,849,966 Common Shares or approximately 5.3% 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 30+ years of industry experience. Mr. Roszell was the President and Chief Executive Officer of Raging River Exploration Inc. ("**Raging River**") from 2012 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 2018 until December 2019. Mr. Roszell was the President and Chief Executive Officer of Wild Stream Exploration Inc. ("**Wild Stream**") from 2009 to 2012. He was also the President and Chief Executive Officer of Wild River Resources Ltd. ("**Wild River**") from 2007 until 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. 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, President, Chief Operating Officer and a Director***

Mr. Jaskela is a professional engineer with 22 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 to 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 2012. 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 has over 10 years of management, accounting and corporate finance experience. Ms. Horvath was previously a founder and the Controller of Raging River and prior thereto a Senior Financial Accountant with Wild Stream. Prior to Wild Stream, Ms. Horvath worked in the audit and assurance practice of PricewaterhouseCoopers LLP. 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 20 years of industry experience. Mr. Danku held several officer positions at Raging River from 2014 through 2018, including Vice-President, Engineering, Vice-President, Business Development and Vice-President, Exploitation. Previously, Mr. Danku held a Team Lead position at Surge Energy Inc. ("**Surge**") and Senior engineering roles at Pace Oil & Gas Ltd. (April 2012 – October 2013), Wild Stream (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, Exploration from May 2011 to February 28, 2017. He started his career at POCO Petroleum 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 land professional with over 19 years of industry experience. Mr. Rideout was the Vice President, 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, 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.

***Brad Christman, Vice President, Production***

Mr. Christman has over 20 years of industry experience in Canada and in the United States. Mr. Christman was the Manager, Production and Facilities at Raging River from March 2012 until Raging River's sale to Baytex in August 2018, following which Mr. Christman was the Manager, Production and Facilities at Baytex until March 2020. Prior to Raging River, Mr. Christman worked as an Area Coordinator at Wild Stream.

***Chandra Henry, Director***

Ms. Henry is currently Chief Financial Officer and Chief Compliance Officer of Longbow Capital Inc. ("**Longbow**") and a director of Bonavista Energy Corporation. Ms. Henry was 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. In addition, Ms. Henry is a Fundamentals of Sustainability Accounting (FSA) level 2 candidate.

***Phillip Knoll, Director***

Mr. Knoll is a Professional Engineer and has been the President of Knoll Energy Inc. since 2006. Mr. Knoll currently serves on the board of directors of Altagas Ltd. and was formerly a director of Rally Energy Corp. and Bankers Petroleum Ltd. 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 directors 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. 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.

***Kam Sandhar, Director***

Mr. Sandhar is currently the Executive Vice-President, Strategy & Corporate Development of Cenovus. Mr. Sandhar has nearly 20 years of experience in the oil and gas industry and has extensive expertise in strategy, business development, finance and investor relations. Prior to joining Cenovus in 2013, Mr. Sandhar spent 9 years at Peters & Co. Limited where he served as a Principal and oil and gas analyst, covering a wide array of Canadian, U.S. and international oil and gas companies. Mr. Sandhar started his career at Deloitte LLP where he focused on oil and gas audit and taxation. Mr. Sandhar is a Chartered Professional Accountant and a member of the Chartered Professional Accountants of Alberta. He holds a Bachelor of Commerce degree from the University of Calgary.

***Edward (Ted) Brown, Corporate Secretary***

Mr. Brown is a partner and Co-Leader of the Business Law Group at 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.

Other than as described below, 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.

David Pearce is a director of Kaisen Energy Corp. ("**Kaisen**"). On December 8, 2021, Kaisen sought and obtained protection under the *Companies' Creditors Arrangement Act* ("**CCAA**") pursuant to an Order (the "**Initial Order**") of the Court of Queen's Bench of Alberta (the "**Court**"). The Initial Order authorized Kaisen to begin a Court-supervised restructuring and granted Kaisen various relief, including but not limited to, an initial stay of proceedings against Kaisen and its assets, appointing Ernst & Young Inc. as Monitor (the "**Monitor**"), and providing Kaisen the opportunity to prepare and file a plan of arrangement under the CCAA for the consideration of its creditors and other stakeholders. On December 17, 2021, the Court approved a plan of arrangement under the CCAA including provisions relating to receiving creditor and stakeholder approval for the plan of arrangement. The process under the CCAA in respect of Kaisen is ongoing.

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 10, 2022, 223,727,180 Common Shares are issued and outstanding as fully paid and non-assessable. In addition, the Corporation has 8,594,288 Warrants and stock options to purchase 9,366,669 Common Shares outstanding as of March 10, 2022.

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, 2021 to March 9, 2022.

### Price Range and Trading Volume

Period	High (\$)	Low (\$)	Volume
<b>2021</b>			
January .....	3.21	2.32	12,688,065
February .....	4.15	2.81	9,849,356
March .....	4.80	3.72	17,599,398
April .....	4.57	3.73	9,181,527
May .....	4.73	4.14	8,450,943
June .....	4.66	4.06	37,121,635
July .....	4.41	3.47	11,256,146
August .....	4.17	3.39	10,070,399
September.....	4.90	3.74	19,088,270
October.....	4.95	4.40	23,319,097
November.....	5.31	4.33	25,341,298
December .....	5.38	4.32	20,706,598
<b>2022</b>			
January .....	7.29	5.26	26,506,955
February .....	7.66	6.75	25,464,072
March (1 – 9).....	7.62	6.80	12,410,504

## 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.**

### 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 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 may be volatile for a variety of reasons including market uncertainties over the supply and demand of these commodities due to the current state of the world economies, the impacts of the Russian Ukrainian conflict on the supply and demand of oil and natural gas and the world economy, the ongoing COVID-19 pandemic, OPEC+ actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries and conflicts in the Middle East. Prices for oil and natural gas are also subject to the availability of foreign markets and the Corporation's ability to access such markets. A material decline in prices could result in a reduction of the

Corporation's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the Corporation's carrying value of its reserves, future borrowing capacity, revenues, profitability and cash flows from operating activities and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

The Corporation has various take or pay pipeline service agreements to deliver its heavy oil production from Marten Hills to market that expire in 2031. For details of the Corporation's transportation agreements in place as at December 31, 2021, see the Corporation's audited financial statements for the year ended December 31, 2021, which have been filed on SEDAR and may be viewed under the Corporation's profile at [www.sedar.com](http://www.sedar.com).

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.

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

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 "*Risk Factors – 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 "*Risk Factors – Prices, Markets and Marketing*".

#### **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.***

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

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

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

## **Russian Ukrainian Conflict**

***The Russian Ukrainian conflict and the related sanctions imposed by many Western countries will impact the world economy and the supply of oil and natural gas as Russia is a significant exporter of both oil and natural gas.***

In February 2022, Russian military forces invaded Ukraine. In response, Ukrainian military personnel and civilians are actively resisting the invasion. Many countries throughout the world have provided aid to the Ukraine in the form of financial aid and in some cases military equipment and weapons to assist in their resistance to the Russian invasion. The North Atlantic Treaty Organization ("**NATO**") has also mobilized forces to NATO member countries that are close to the conflict as deterrence to further Russian aggression in the region. The outcome of the conflict is uncertain and is likely to have wide-ranging consequences on the peace and stability of the region and the world economy.

In addition, certain countries including Canada and the United States, have imposed strict financial and trade sanctions against Russia, which sanctions may have far reaching effects on the global economy. As part of the sanctions package, the German government paused the certification process for the 1,200 km Nord Stream 2 natural gas pipeline that was built to carry natural gas from Russia to Germany. Russia is a major exporter of oil and natural gas. Disruption of supplies of oil and natural gas from Russia could cause a significant worldwide supply shortage of oil and natural gas and have a significant impact on worldwide prices of oil and natural gas. A lack of supply and high prices of oil and natural gas could have a significant adverse impact on the world economy. The long-term impacts of the conflict and the sanctions imposed on Russia remain uncertain.

## **COVID-19 and its Effect on the Global Economy**

***The COVID-19 pandemic continues to cause disruptions in economic activity in Canada and internationally and impact demand for oil, natural gas liquids and natural gas.***

In March 2020, the World Health Organization declared COVID-19 a global pandemic, prompting many countries around the world to close international borders and order the closure of institutions and businesses deemed non-essential. This resulted in a swift and significant reduction in economic activity in Canada and internationally along with a sudden drop in demand for oil, liquids and natural gas. Since 2020, oil prices have largely recovered from their historic lows, but price support from future demand remains uncertain as countries experience varying degrees of virus outbreak and newly emerging virus variants following efforts to re-open local economies and international borders. Low commodity prices resulting from reduced demand associated with the impact of COVID-19 has had, and may continue to have, a negative impact on the Corporation's operational results and financial condition. Low prices for oil, liquids and natural gas will reduce the Corporation's cash flows from operating activities and impact the Corporation's level of capital investment and may result in the reduction of production at certain producing properties.

While the duration and full impact of the COVID-19 pandemic is not yet known, effects of COVID-19 may also include disruptions to production operations, access to materials and services, increased employee absenteeism from illness, and temporary closures of the Corporation's facilities.

The extent to which the Corporation's operational and financial results are affected by COVID-19 will depend on various factors and consequences beyond its control such as the duration and scope of the pandemic; additional actions taken by business and government in response to the pandemic; and the speed and effectiveness of responses to combat the virus. Additionally, COVID-19 and its effect on local and global economic conditions stemming from the pandemic could also aggravate the other risk factors identified herein, the extent of which is not yet known.

### **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. 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.

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

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

### **Water Availability and Disposal**

***The Corporation's operations are dependent upon the availability of water and its ability to dispose of produced water from drilling and production activities. The Corporation does not currently utilize hydraulic fracturing but may do so in the future.***

Water is an essential component of the Corporation's drilling and enhanced oil recovery processes. Limitations or restrictions on the Corporation's ability to secure sufficient amounts of water (including limitations resulting from natural causes such as drought), could materially and adversely impact its operations. Severe drought conditions can result in local water authorities taking steps to restrict the use of water in their jurisdiction for drilling, completion and enhance oil recovery operations in order to protect the local water supply. If the Corporation is unable to obtain water

to use in its operations from local sources, it may need to be obtained from new sources and transported to drilling sites, resulting in increased costs, which could have a material adverse effect on its financial condition, results of operations, and cash flows.

In addition, the Corporation must dispose of the fluids produced from oil, liquids and natural gas production operations, including produced water, which it does directly or through the use of third-party vendors. Water injection and disposal into geologic formations has caused increased occurrence of seismic events in certain areas. The legal requirements related to the disposal of produced water into a non-producing geologic formation by means of underground injection wells are subject to change based on concerns of the public or governmental authorities regarding such disposal activities.

Another consequence of seismic events may be lawsuits alleging that disposal well operations have caused damage to neighboring properties or otherwise violated laws and regulations regarding waste disposal. These developments could result in additional regulation and restrictions on the use of injection wells by the Corporation or by commercial disposal well vendors that the Corporation may use from time to time to dispose of produced water. Increased regulation and attention given to induced seismicity could also lead to greater opposition, including litigation to limit or prohibit oil and natural gas activities utilizing injection wells for produced water disposal. Any one or more of these developments may result in the Corporation or its vendors having to limit disposal well volumes, disposal rates and pressures or locations, or require the Corporation or its vendors to shut down or curtail the injection of produced water into disposal wells, which events could have a material adverse effect on the Corporation's business, financial condition, and results of operations.

### **Hydraulic Fracturing**

***If the hydraulic fracturing moratorium is not lifted in New Brunswick, the Corporation would not be able to complete any additional development activities with respect to its McCully Field assets.***

Although hydraulic fracturing is not necessary for drilling and completion operations for Headwater's Marten Hills assets in Alberta, Headwater would require hydraulic fracturing in connection with any future drilling and completion activities it conducts 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 uncertainty 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 will be materially and adversely affected.

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

## **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 flows.***

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 hydrocarbons 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 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*".

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

## **Royalty Regimes**

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

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

## **Environmental**

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

All phases of the 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 – Regulatory Authorities and Environmental Regulation*".

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require

the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it is 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.

## **Climate Change**

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

Global climate issues continue to attract public and scientific attention. Numerous reports, including reports from the Intergovernmental Panel on Climate Change, have engendered concern about the impacts of human activity, especially hydrocarbon combustion, on global climate issues. In turn, increasing public, government, and investor attention is being paid to global climate issues and to emissions of greenhouse gases ("GHG"), including emissions of carbon dioxide and methane from the production and use of oil, liquids and natural gas. The majority of countries across the globe, including Canada, have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In addition, during the course of the 2021 United Nations Climate Change Conference in Glasgow, Scotland, Canada's Prime Minister Justin Trudeau made several pledges aimed at reducing Canada's GHG emissions and environmental impact. As discussed below, the Corporation faces both transition risks and physical risks associated with climate change and climate change policy and regulations.

### ***Transition risks***

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

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

Given the perceived elevated long-term risks associated with policy development, regulatory changes, public and private legal challenges, or other market developments related to climate change, there have also been efforts in recent years affecting the investment community, including investment advisors, sovereign wealth funds, banks, public pension funds, universities and other institutional investors, promoting direct engagement and dialogue with companies in their portfolios on climate change action (including exercising their voting rights on matters relating to climate change) and increased capital allocation to investments in low-carbon assets and businesses while decreasing the carbon intensity of their portfolios through, among other measures, divestments of companies with high exposure to GHG-intensive operations and products. Certain stakeholders have also pressured insurance providers and commercial and investment banks to reduce or stop financing, and providing insurance coverage to oil and natural gas

and related infrastructure businesses and projects. The impact of such efforts requires the Corporation's management to dedicate significant time and resources to these climate change-related concerns, may adversely affect the Corporation's operations, the demand for and price of the Corporation's securities and may negatively impact the Corporation's cost of capital and access to the capital markets.

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

### ***Physical risks***

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

### **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.

Additionally, the Corporation has U.S. dollar denominated heavy oil, natural gas and natural gas liquids marketing arrangements.

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.

For details of the Corporation's foreign exchange contracts in place as at December 31, 2021, see the Corporation's audited financial statements for the year ended December 31, 2021, which have been filed on SEDAR and may be viewed under the Corporation's profile at [www.sedar.com](http://www.sedar.com).

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 operating activities, borrowings and possible future equity sales, the Corporation's ability to do so is dependent on, among other factors:

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

Further, if the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. The conditions in, or affecting, the 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 operating activities will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The Corporation may be required to seek additional equity financing on terms that are highly dilutive to existing Shareholders. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

### **Additional Funding Requirements**

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

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and, from time to time, the Corporation may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. Failure to obtain financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce its operations. Due to the conditions in the 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 conditions and the domestic lending landscape, the Corporation may, from time to time, have restricted access to capital and increased borrowing costs. Failure to obtain suitable financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, the Corporation's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be affected

materially and adversely as a result. In addition, the future development of the Corporation's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Alternatively, any available financing may be highly dilutive to existing Shareholders. Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production on the Corporation's properties.

### **Asset Concentration**

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

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

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

### **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.

For details of the Corporation's hedging contracts in place as at December 31, 2021, see the Corporation's audited financial statements for the year ended December 31, 2021, which have been filed on SEDAR and may be viewed under the Corporation's profile at [www.sedar.com](http://www.sedar.com).

### **Inflation and Cost Management**

***A failure to secure the services and equipment necessary to the Corporation's operations for the expected price, on the expected timeline, or at all, may have an adverse effect on the Corporation's financial performance and cash flows.***

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

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

### **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.



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

### **Non-Governmental Organizations**

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

The 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 from the federal, provincial or municipal governments, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses, and direct legal challenges, including the possibility of climate-related litigation. There is no guarantee that the Corporation will be able to satisfy the concerns of the special interest groups and non-governmental organizations and attempting to address such concerns may require the Corporation to incur significant and unanticipated capital and operating expenditures.

### **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 "*Risk Factors – Climate Change*".

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

## **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 hydrocarbons 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.

## **Dilution**

*The Corporation may issue additional Common Shares or other dilutive securities, 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 Land and Rights Claims**

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

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

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

The Canadian federal and provincial governments have a duty to consult with Indigenous people when contemplating actions that may adversely affect the asserted or proven Indigenous or treaty rights and, in certain circumstances, accommodate their concerns. The scope of the duty to consult by federal and provincial governments varies with the circumstances and is often the subject of ongoing litigation. The fulfillment of the duty to consult Indigenous people and any associated accommodations may adversely affect the Corporation's ability to, or increase the timeline to, obtain or renew, permits, leases, licences and other approvals, or to meet the terms and conditions of those approvals. For example, a recent British Columbia Supreme Court decision determined that the cumulative impacts of government sanctioned industrial development on the traditional territories of a First Nations group in northeast British Columbia breached that group's treaty rights. Going forward, this decision may have significant impacts on the regulation of industrial activities in northeast British Columbia. Further, it may lead to similar claims of cumulative effects across Canada in other areas covered by numbered treaties. The long-term impacts of and associated risks of the decision on the Canadian oil and natural gas industry and the Corporation remain uncertain.

In addition, the federal government has introduced legislation to implement the United Nations Declaration on the Rights of Indigenous Peoples ("UNDRIP"). Other Canadian jurisdictions, including British Columbia, have also introduced or passed similar legislation, or begun considering the principles and objectives of UNDRIP, or may do so in the future. The means and timelines associated with UNDRIP's implementation by government is uncertain; additional processes may be created or legislation amended or introduced associated with project development and operations, further increasing uncertainty with respect to project regulatory approval timelines and requirements. See "*Industry Conditions – Indigenous Rights*".

### **Breach of Confidentiality**

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

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

### **Income Taxes**

***Taxation authorities may reassess the Corporation's tax returns.***

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

Income tax laws relating to the 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 may 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 is 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 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.

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, 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 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.***

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

- availability of processing capacity;
- availability and proximity of pipeline capacity;
- availability of storage capacity;
- availability of, and the ability to acquire, water supplies needed for drilling, hydraulic fracturing, and waterfloods or the Corporation's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- effects of inclement and severe weather events, including fire, drought and flooding;
- availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- availability and productivity of skilled labour; and
- regulation of the 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 may enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. 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 operating in the Canadian oil and gas industry are subject to extensive regulation and control of operations (including with respect to land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government as well as with respect to the pricing and taxation of petroleum and natural gas through legislation enacted by, and agreements among, the federal and provincial governments of Canada, all of which should be carefully considered by investors in the Canadian oil and gas industry. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments governments may enact in the future.

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

The discussion below outlines some of the principal aspects of the legislation, regulations, agreements, orders, directives and a summary of other pertinent conditions that impact the oil and gas industry in Canada, specifically in the provinces of Alberta and New Brunswick, where the Corporation's assets are primarily located. Although the Corporation also has undeveloped land in the province of Saskatchewan, it does not currently have any significant operations in either province. While these matters do not affect the Corporation's operations in any manner that is materially different than the manner in which they affect other similarly-sized industry participants with similar assets and operations, investors should consider such matters carefully.

### **Pricing and Marketing in Canada**

#### ***Crude Oil***

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

Global oil markets have recovered significantly from price drops resulting from the COVID-19 pandemic. In the first quarter of 2022, oil prices have risen to the highest levels since 2014 due to tight supply and a resurgence in demand. OPEC+ forecasts robust growth in world oil demand in 2022, despite newly emerging COVID-19 variants, expected interest rate increases in major economies and other uncertainties with respect to the world economy.

#### ***Natural Gas***

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



### ***Natural Gas Liquids ("NGLs")***

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

### **Exports from Canada**

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

### **Transportation Constraints and Market Access**

Under the Canadian Constitution, the development and operation of interprovincial and international pipelines fall within the federal government's jurisdiction and, under the CERA, new interprovincial and international pipelines require a federal regulatory review and Cabinet approval before they can proceed. However, recent years have seen a perceived lack of policy and regulatory certainty in this regard such that, even when projects are approved, they often face delays due to actions taken by provincial and municipal governments and legal opposition related to issues such as Indigenous rights and title, the government's duty to consult and accommodate Indigenous peoples and the sufficiency of all relevant environmental review processes. Export pipelines from Canada to the United States face additional unpredictability as such pipelines also require approvals from several levels of government in the United States.

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

### ***Oil Pipelines***

#### *Specific Pipeline Updates*

The Enbridge Inc. Line 3 Replacement from Hardisty, Alberta to Superior, Wisconsin came into service in October 2021. The Line 3 Replacement, originally expected to be in-service in late 2019, faced significant permitting difficulties in the United States, resulting in the two-year delay. The pipeline provides an incremental 370,000 Bbls/d of export capacity from Western Canada into the United States.

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of political opposition in British Columbia, the federal government acquired the Trans Mountain Pipeline in August 2018. Following the resolution of a number of legal challenges and a second regulatory hearing, construction on the Trans Mountain Pipeline expansion commenced in late 2019 and it is expected to be in-service in December 2022; however, there continues to be uncertainty about whether the December expected in-service date will be met.

In November 2020, the Attorney General of Michigan filed a lawsuit to terminate an easement that allows the Enbridge Line 5 pipeline system to operate below the Straits of Mackinac, attempting to force the lines comprising this segment of the pipeline system to be shut down. Enbridge filed a federal complaint in late November 2020 in the United States District Court for the Western District of Michigan and is seeking an injunction to prevent the termination of the easement. Enbridge stated in January 2021 that it intends to defy the shut down order, as the dual pipelines are in full compliance with U.S. federal safety standards. The Government of Canada invoked a 1977 treaty with the United

States on October 4, 2021, triggering bilateral negotiations over the pipeline. On December 15, 2021, Enbridge moved to transfer the Attorney General's lawsuit from Michigan State Court to United States Federal Court.

### ***Marine Tankers***

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

### ***Natural Gas and LNG***

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

Required repairs or upgrades to existing pipeline systems in Western Canada have also led to reduced capacity and apportionment of access, the effects of which have been exacerbated by storage limitations. In October 2020, TC Energy received federal approval to expand the NGTL System and the expanded NGTL System is expected to be fully operational by April 2022.

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

While a number of LNG export plants have been proposed in Canada, regulatory and legal uncertainty, social and political opposition and changing market conditions have resulted in the cancellation or delay of many of these projects. Nonetheless, in October 2018, the joint venture partners of the LNG Canada LNG export terminal announced a positive final investment decision. Once complete, the project will allow producers in northeastern British Columbia to transport natural gas to the LNG Canada liquefaction facility and export terminal in Kitimat, British Columbia via the Coastal GasLink pipeline (the "**CGL Pipeline**"). Pre-construction activities on the LNG Canada facility began in November 2018, with a completion target of 2025.

In May 2020, TC Energy sold a 65% equity interest in the CGL Pipeline to investment companies KKR & Co Inc. and Alberta Investment Management Corporation while remaining the pipeline operator. Despite its approval, the CGL Pipeline has faced legal and social opposition. For example, protests involving the Hereditary Chiefs of the Wet'suwet'en First Nation and their supporters have delayed construction activities on the CGL Pipeline, although construction is proceeding. As of December 2021, construction of the CGL Pipeline is approximately 60% complete.

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

### **International Trade Agreements**

Canada is party to a number of international trade agreements with other countries around the world that generally provide for, among other things, preferential access to various international markets for certain Canadian export products. Examples of such trade agreements include the Comprehensive Economic and Trade Agreement, the Comprehensive and Progressive Agreement for Trans-Pacific Partnership and, most prominently, the USMCA, which replaced the former NAFTA on July 1, 2020. Because the United States remains Canada's primary trading partner and the largest international market for the export of oil, natural gas and NGLs from Canada, the implementation of the USMCA could impact Canada's oil and gas industry at large, including the Corporation's business.

While the proportionality rules in Article 605 of NAFTA previously prevented Canada from implementing policies that limit exports to the United States and Mexico relative to the total supply produced in Canada, the USMCA does not contain the same proportionality requirements. This may allow Canadian producers to develop a more diversified

export portfolio than was possible under NAFTA, subject to the construction of infrastructure allowing more Canadian production to reach eastern Canada, Asia and Europe.

## **Land Tenure**

### *Mineral rights*

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

All of the provinces of Western Canada have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a disposition. In addition, Alberta has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for new leases and licences; British Columbia has a policy of "zone specific retention" that allows a lessee to continue a lease for zones in which they can demonstrate the presence of oil or natural gas, with the remainder reverting to the Crown.

In addition to Crown ownership of the rights to oil and natural gas, private ownership of oil and natural gas (i.e. freehold mineral lands) also exists in Western Canada. Rights to explore for and produce privately owned oil and natural gas are granted by a lease or other contract on such terms and conditions as may be negotiated between the owner of such mineral rights and companies seeking to explore for and/or develop oil and natural gas reserves.

An additional category of mineral rights ownership includes ownership by the Canadian federal government of some legacy mineral lands and within Indigenous reservations designated under the *Indian Act* (Canada). Indian Oil and Gas Canada manages subsurface and surface leases in consultation with applicable Indigenous peoples, for the exploration and production of oil and natural gas on Indigenous reservations through *An Act to Amend the Indian Oil and Gas Act* and the accompanying regulations. The Corporation does not have operations on Indigenous reserve lands.

### *Surface rights*

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

## **Royalties and Incentives**

### *General*

Each province has legislation and regulations in place to govern Crown royalties and establish the royalty rates that producers must pay in respect of the production of Crown resources. The royalty regime in a given province is in addition to applicable federal and provincial taxes and is a significant factor in the profitability of oil sands projects and oil, natural gas and NGL production. Royalties payable on production from lands where the Crown does not hold

the mineral rights are negotiated between the mineral freehold owner and the lessee, though certain provincial taxes and other charges on production or revenues may be payable.

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

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

## ***Alberta***

### *Crown royalties*

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

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

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

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

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

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

### *Freehold royalties and taxes*

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

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

### ***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 1-49m3, to 12% at volumes equal to or greater than 720 m3.

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.

## **Regulatory Authorities and Environmental Regulation**

### ***General***

The Canadian oil and gas industry is subject to environmental regulation under a variety of Canadian federal, provincial, territorial, and municipal laws and regulations, all of which are subject to governmental review and revision from time to time. Such regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well, facility and pipeline sites. Compliance with such regulations can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability, and the imposition of material fines and penalties. In addition, future changes to environmental legislation, including legislation related to air pollution and GHG emissions (typically measured in terms of their global warming potential and expressed in terms of carbon dioxide equivalent ("**CO<sub>2</sub>e**")), may impose further requirements on operators and other companies in the oil and gas industry.

### ***Federal***

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

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

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

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

The Government of Alberta has submitted a reference question to the Alberta Court of Appeal regarding the constitutionality of the IAA, but this matter remains before the courts.

### *Alberta*

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

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

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

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

The AER has developed monitoring and reporting requirements that apply to all oil and natural gas producers working in certain areas where the likelihood of an earthquake is higher, and implemented the requirements in *Subsurface Order Nos. 2, 6, and 7*. The regions with seismic protocols in place are Fox Creek, Red Deer, and Brazeau. The Corporation does not have operations in Fox Creek, Red Deer and Brazeau.

### *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 uncertainty remains regarding the availability of such exemptions. At the present time, no exemption has been granted to allow hydraulic fracturing on the Corporation's lands in the McCully Field in New Brunswick.

See "*Risk Factors – Hydraulic Fracturing*".

## ***Liability Management***

### *Alberta*

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

Complementing the AB LM Framework and the AB LMR Program, Alberta's OGCA establishes an orphan fund (the "**Orphan Fund**") to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program and the AB OWL Program if a licensee or working interest participant becomes insolvent or is unable to meet its obligations. Licensees in the AB LLR Program and the AB OWL Program fund the Orphan Fund

through a levy administered by the AER. However, given the increase in orphaned oil and natural gas assets, the Government of Alberta has loaned the Orphan Fund approximately \$335 million to carry out abandonment and reclamation work. In response to the COVID-19 pandemic, the Government of Alberta also covered \$113 million in levy payments that licensees would otherwise have owed to the Orphan Fund, corresponding to the levy payments due for the first six months of the AER's fiscal year. A separate orphan levy applies to persons holding licences subject to the AB LF Program. Collectively, these programs are designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines.

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

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

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

In addition to the AB LCA, Directive 088 also implemented other new liability management programs under the AB LM Framework. These include the AB LM Program and the AB IR Program. Under the AB LM Program the AER will continuously monitor licensees over the life-cycle of a project. If, under the AB LM Program, the AER identifies a licensee as high risk, the regulator may employ various tools to ensure that a licensee meets its regulatory and liability obligations. In addition, under the AB IR Program the AER sets industry wide spending targets for abandonment and reclamation activities. Licensees are then assigned a mandatory licensee specific target based on the licensee's



proportion of provincial inactive liabilities and the licensee's level of financial distress. Certain licensees may also elect to provide the AER with a security deposit in place of their closure spend target.

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

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

#### *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.

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

As part of an announcement of federal relief for Canada's oil and gas industry in response to COVID-19, in May 2020 the federal government pledged \$1.72 billion to clean up orphan and inactive wells in Alberta, Saskatchewan and British Columbia. These funds were administered by regulatory authorities in each province and disbursed through various provincial programs. The majority of these funds have now been allocated and disbursed.

#### ***Climate Change Regulation***

Climate change regulation at each of the international, federal and provincial levels has the potential to significantly affect the future of the oil and gas industry in Canada. These impacts are uncertain and it is not possible to predict what future policies, laws and regulations will entail. Any new laws and regulations (or additional requirements to existing laws and regulations) could have a material impact on the Corporation's operations and cash flow.

#### *Federal*

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

During the course of the 2021 United Nations Climate Change Conference in Glasgow, Scotland, Canada's Prime Minister Justin Trudeau made several pledges aimed at reducing Canada's GHG emissions and environmental impact, including: (i) reducing methane emissions in the oil and gas sector to 75% of 2012 levels by 2030; (ii) ceasing export of thermal coal by 2030; (iii) imposing a cap on emissions from the oil and gas sector; (iv) halting direct public funding

to the global fossil fuel sector by the end of 2022; and (v) committing that all new vehicles sold in the country will be zero-emission on or before 2040.

The Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change in 2016, setting out a plan to meet the federal government's 2030 emissions reduction targets. On June 21, 2018, the federal government enacted the *Greenhouse Gas Pollution Pricing Act* (the "**GGPPA**"), which came into force on January 1, 2019. This regime has two parts: an output-based pricing system ("**OBPS**") for large industry (enabled by the *Output-Based Pricing System Regulations*) and a fuel charge (enabled by the *Fuel Charge Regulations*), both of which impose a price on CO<sub>2</sub>e emissions. This system applies in provinces and territories that request it and in those that do not have their own equivalent emissions pricing systems in place that meet the federal standards and ensure that there is a uniform price on emissions across the country. Originally under the federal plans, the price was set to escalate by \$10 per year until it reaches a maximum price of \$50/tonne of CO<sub>2</sub>e in 2022; however, on December 11, 2020, the federal government announced its intention to continue the annual price increases beyond 2022, such that, commencing in 2023, the benchmark price per tonne of CO<sub>2</sub>e will increase by \$15 per year until it reaches \$170/tonne of CO<sub>2</sub>e in 2030. Starting April 1, 2022, the minimum price permissible under the GGPPA is \$50/tonne of CO<sub>2</sub>e. In addition, on March 5, 2021, the federal government introduced for comment the *Greenhouse Gas Offset Credit System Regulations (Canada)* (the "**Federal Offset Credit Regulations**"). The proposed Federal Offset Credit Regulations are intended to establish a regulatory framework to allow certain kinds of projects to generate and sell offset credits for use in the federal OBPS. The final Federal Offset Credit Regulations are currently targeted for publication in mid-2022.

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

On April 26, 2018, the federal government passed the *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* (the "**Federal Methane Regulations**"). The Federal Methane Regulations seek to reduce emissions of methane from the oil and natural gas sector, and came into force on January 1, 2020. By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and the intentional venting of methane and ensure that oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and natural gas facilities are permitted to vent. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

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

As part of its efforts to provide relief to Canada's oil and gas industry in light of the COVID-19 pandemic, the federal government announced the \$750 million Emissions Reduction Fund ("**ERF**"), intended to help the oil and gas sectors to reduce the production of methane and other GHG emissions. Funds disbursed through the ERF will primarily take the form of repayable contributions to onshore and offshore oil and gas firms. Of the \$750 million in funding, \$675 million was allocated to the Onshore Deployment Program, while \$75 million was dedicated to the Offshore Deployment Program and the Offshore RD&D (research, development and demonstration) Program. Natural Resources Canada expects that all funding for onshore projects will be allocated by March 2022, while funding for offshore projects will be allocated by March 2023.

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

In the November 23, 2021 Speech from the Throne, the federal government restated its commitment to achieve net-zero emission by 2050. In pursuit of this objective, the government's proposed actions include: (i) moving to cap and cut oil and gas sector emissions; (ii) investing in public transit and mandating the sale of zero-emission vehicles; (iii) increasing the federally imposed price on pollution; (iv) investing in the production of cleaner steel, aluminum, building products, cars, and planes; (v) addressing the loss of biodiversity by continuing to strengthen partnerships

with First Nations, Inuit, and Métis, to protect nature and the traditional knowledge of those groups; (vi) creating a Canada Water Agency to safeguard water as a natural resource and support Canadian farmers; (vii) strengthening action to prevent and prepare for floods, wildfires, droughts, coastline erosion, and other extreme weather worsened by climate change; and (viii) helping build back communities impacted by extreme weather events through the development of Canada's first-ever National Adaptation Strategy.

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

The Government of Canada is also in the midst of developing a carbon capture utilization and storage ("CCUS") strategy. CCUS is a technology that captures carbon dioxide from facilities, including industrial or power applications, or directly from the atmosphere. The captured carbon dioxide is then compressed and transported for permanent storage in underground geological formations or used to make new products such as concrete. The federal government has indicated that urgent steps are necessary to ramp up CCUS in Canada, as this will be a critical element of the plan to reach net-zero by 2050.

### *Alberta*

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

In June 2019, the fuel charge element of the federal backstop program took effect in Alberta. On April 1, 2022, the carbon tax payable in Alberta will increase from \$40 to \$50 per tonne of CO<sub>2</sub>e, and will continue to increase at a rate of \$15 per year until it reaches \$170 per tonne in 2030. In December 2019, the federal government approved Alberta's *Technology Innovation and Emissions Reduction* ("TIER") regulation, which applies to large emitters. The TIER regulation came into effect on January 1, 2020 and replaces the previous *Carbon Competitiveness Incentives Regulation*. The TIER regulation meets the federal benchmark stringency requirements for emissions sources covered in the regulation, but the federal backstop continues to apply to emissions sources not covered by the regulation.

The TIER regulation applies to emitters that emit more than 100,000 tonnes of CO<sub>2</sub>e per year in 2016 or any subsequent year. The initial target for most TIER-regulated facilities is to reduce emissions intensity by 10% as measured against that facility's individual benchmark, with a further 1% reduction in each subsequent year. The facility-specific benchmark does not apply to all facilities, such as those in the electricity sector, which are compared against the good-as-best-gas standard. Similarly, for facilities that have already made substantial headway in reducing their emissions, a different "high-performance" benchmark is available. Under the TIER regulation, certain facilities in high-emitting or trade exposed sectors can opt-in to the program in specified circumstances if they do not meet the 100,000 tonne threshold. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports and facilities that are unable to achieve their targets may either purchase credits from other facilities, purchase carbon offsets, or pay a levy to the Government of Alberta.

On September 1, 2020, the Government of Alberta announced \$750 million in spending from the TIER fund to support projects that help industries reduce their carbon emissions. Such projects include CCUS, energy efficiency, and increased methane management initiatives. An additional \$176 million in spending from the TIER fund was announced for similar GHG reduction projects on November 1, 2021.

The Government of Alberta aims to lower annual methane emissions by 45% by 2025. The Government of Alberta enacted the *Methane Emission Reduction Regulation* on January 1, 2020, and the AER simultaneously released an updated edition of *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*. The release of the updated Directive 060 complements a previously released update to *Directive 017: Measurement Requirements for*

*Oil and Gas Operations* that took effect in December 2018. In November 2020, the Government of Canada and the Government of Alberta announced an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in Alberta.

### *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 in-province electricity sales in New Brunswick is electricity from renewable sales.

In March, 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.

In December, 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 took effect on April 1, 2020. Under the GMTA, a charge equivalent to the federal fuel charge applies 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 rebates the fuel charge collected on natural gas to Liberty Utilities, the provincial distributor of natural gas for utilities purposes, which amount is then credited to customers.

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 CO<sub>2</sub>e 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 CO<sub>2</sub>e but less than 50,000 CO<sub>2</sub>e 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. In September 2020, the Government of Canada notified the Government of New Brunswick that its output-based pricing system for industrial emitters satisfied federal standards; however, the transition timeline from the federal program to the provincial program remains under discussion.

### **Indigenous Rights**

Constitutionally mandated government-led consultation with and, if applicable, accommodation of, the rights of Indigenous groups impacted by regulated industrial activity, as well as proponent-led consultation and accommodation or benefit sharing initiatives, play an increasingly important role in the Western Canadian oil and gas industry. In addition, Canada is a signatory to the UNDRIP and the principles set forth therein may continue to influence the role of Indigenous engagement in the development of the oil and gas industry in Western Canada. For example, in November 2019, the *Declaration on the Rights of Indigenous Peoples Act* ("**DRIPA**") became law in British

Columbia. The DRIPA aims to align British Columbia's laws with UNDRIP. In June 2021, the *United Nations Declaration on the Rights of Indigenous Peoples Act* ("**UNDRIP Act**") came into force in Canada. Similar to British Columbia's DRIPA, the UNDRIP Act requires the Government of Canada to take all measures necessary to ensure the laws of Canada are consistent with the principles of UNDRIP and to implement an action plan to address UNDRIP's objectives.

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

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

On October 7, 2021, the Government of British Columbia and the BRFN reached an initial agreement in response to the Blueberry Decision in which the parties agreed to negotiate a land management process for BRFN territory, and certain previously authorized forestry and oil and gas projects were put on hold pending further negotiation. Currently, the Government of British Columbia and the BRFN are in the midst of negotiations to finalize a new regime for assessment, authorization and management of industrial activities on BRFN territory in a manner consistent with the Blueberry Decision. The BRFN elected Judy Desjarlais as Chief in January 2022, replacing Marvin Yahey Sr. in the role. The long-term impacts and risks of the Blueberry Decision and the election of a new BRFN Chief on the Canadian oil and gas industry remain uncertain.

## **LEGAL PROCEEDINGS**

Headwater is not a party to any legal proceeding nor was it a party to any legal proceeding during the 2021 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, 2021 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 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.

On October 14, 2021, Headwater and Cenovus completed the Secondary Offering pursuant to a short-form prospectus filed by Headwater. Pursuant to the Secondary Offering, Cenovus, through CMHP, sold 50,000,000 Common Shares through a syndicate of underwriters at a price of \$4.55 per Common Share for total gross proceeds to CMHP of \$227.5 million. The Corporation did not receive any of the proceeds of the Secondary Offering. Cenovus paid the underwriters' fees and all expenses of the Secondary Offering.

Prior to the Secondary Offering, CMHP held 50,000,000 Common Shares, which, at the time, represented approximately 24.7% of the issued and outstanding Common Shares on an undiluted basis and approximately 26.8% of the issued and outstanding Common Shares on a fully diluted basis. Pursuant to the Secondary Offering, CMHP disposed of legal and beneficial ownership of 50,000,000 Common Shares, being 100% of the Common Shares held by CMHP at that time.

As a result of the completion of the Secondary Offering, the Investor Agreement automatically terminated in accordance with its terms as Cenovus no longer held, directly or indirectly, any Common Shares. The Investor Agreement provided CMHP with certain contractual rights related to, among other things, the nomination of directors of the Corporation. In connection with the termination of the Investor Agreement, Sarah Walters, who was a nominee of CMHP on the Board, resigned as a director of the Corporation effective upon completion of the Secondary Offering. Kam Sandhar, who was previously nominated to the Board by CMHP pursuant to the Investor Agreement, remained on the Board notwithstanding the termination of the Investor Agreement.

Following completion of the Secondary Offering, CMHP retained the Cenovus Warrants entitling CMHP to purchase 15,000,000 Common Shares, which were subsequently fully-exercised on December 23, 2021.

Cenovus no longer holds, directly or indirectly, Common Shares, representing 10% or more of the issued and outstanding Common Shares.

See "*General Development of the Business – Year 2021 – Secondary Offering of Common Shares*" and "*General Development of the Business – Year 2021 – Exercise of Cenovus Warrants*" for more information about the Secondary Offering and CMHP's exercise of Cenovus Warrants.

#### **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 Kam Sandhar and each 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.

<u>Name and Place of Residence</u>	<u>Independent</u>	<u>Financially Literate</u>	<u>Relevant Education and Experience</u>
Chandra Henry Alberta, Canada	Yes	Yes	Ms. Henry is currently Chief Financial Officer and Chief Compliance Officer of Longbow Capital Inc. and is a director of Bonavista Energy Corporation. Ms. Henry was 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. 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.
Kam Sandhar Alberta, Canada	Yes	Yes	Mr. Sandhar is currently the Executive Vice-President, Strategy and Corporate Development of Cenovus. Mr. Sandhar has nearly 20 years of experience in the oil and gas industry and has extensive expertise in strategy, business development, finance and investor relations. Prior to joining Cenovus in 2013, Mr. Sandhar spent nine years at Peters & Co. Limited where he served as a Principal and oil and gas analyst, covering a wide array of Canadian, U.S. and international oil and gas companies. Mr. Sandhar started his career at Deloitte LLP where he focused on oil and gas audit and taxation. Mr. Sandhar is a Chartered Professional Accountant and a member of the Chartered Professional Accountants of Alberta. He holds a Bachelor of Commerce degree from the University of Calgary.

### **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 such member(s) report to the Audit Committee at the next scheduled meeting such pre-approval and the member(s) 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 KPMG LLP, Chartered Professional Accountants to the Corporation to ensure auditor independence. Fees paid to KPMG LLP and to the

Corporation's former auditor, PricewaterhouseCoopers LLP, for audit and non-audit services in the last two fiscal years are outlined in the following table:

Nature of Services	Fees Paid for Period Ended December 31, 2021	Fees Paid for Period Ended December 31, 2020
Audit Fees <sup>(1)</sup>		
KPMG LLP	\$220,752	\$64,200
PricewaterhouseCoopers LLP	\$nil	\$106,211
Audit-Related Fees <sup>(2)</sup>		
KPMG LLP <sup>(5)</sup>	\$84,263	\$nil
PricewaterhouseCoopers LLP <sup>(5)</sup>	\$48,311	\$nil
Tax Fees <sup>(3)</sup>		
KPMG LLP	\$4,458	\$3,567
PricewaterhouseCoopers LLP	\$nil	\$nil
All Other Fees <sup>(4)</sup>		
KPMG LLP	\$nil	\$nil
PricewaterhouseCoopers LLP	\$nil	\$19,980
<b>Total</b>		
<b>KPMG LLP</b>	<b>\$309,473</b>	<b>\$67,767</b>
<b>PricewaterhouseCoopers LLP</b>	<b>\$48,311</b>	<b>\$126,191</b>

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 (KPMG LLP \$4,458/PricewaterhouseCoopers LLP \$nil 2021 / KPMG LLP \$3,567/PricewaterhouseCoopers LLP \$nil 2020), tax planning (KPMG LLP \$nil/PricewaterhouseCoopers LLP \$nil 2021 / KPMG LLP \$nil/PricewaterhouseCoopers LLP \$nil 2020) and tax advice (KPMG LLP \$nil/PricewaterhouseCoopers LLP \$nil 2021 / KPMG LLP \$nil/PricewaterhouseCoopers LLP \$nil 2020). 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.
- (5) Related to work performed in connection with short form prospectus filed by the Corporation pursuant to the Secondary Offering. These costs were subsequently reimbursed by Cenovus.

#### TRANSFER AGENT AND REGISTRAR

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

#### MATERIAL CONTRACTS

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

#### 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 NI 51-102 during, or related to, Headwater's most recently completed financial year other than GLJ, the independent engineering evaluator for Headwater, and KPMG 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. KPMG LLP has confirmed with respect to the Corporation, that it is 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](http://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 10th day of March, 2022.

(signed) "Neil Roszell"  
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 Exploration Inc. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2021. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2021, 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, 2021, 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 Ltd.	December 31, 2021	Canada	nil	594,628	nil	594,628

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 LTD., Calgary, Alberta, dated February 10, 2022.

Per: (signed) "Chad Lemke"  
Chad Lemke, P.Eng.  
Executive Vice President & COO

## 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 impairment 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 fulfilling 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.