HEADWATER EXPLORATION INC.

ANNUAL INFORMATION FORM

Year Ended December 31, 2022

Dated March 9, 2023

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ABBREVIATIONS AND CONVERSIONS

Oil and Natural Gas Liquids

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

Natural Gas

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

Other

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

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

NOTES ON RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Caution Respecting Reserves Information

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

The recovery and reserve estimates of oil, NGLs and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein. The estimated future net revenue from the production of Headwater's anticipated oil, NGLs and natural gas reserves does not represent the fair market value of Headwater's proposed reserves.

Oil and Gas 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, as applicable.

"**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;

"**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;

"**Credit Facility**" means, collectively, our operating facility and syndicated facility with a syndicate of lenders, as more particularly described under the heading "*General Development of the Business – Recent Developments – Year 2022 – Credit Facility*";

"**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 24, 2023, evaluating the oil and gas properties of the Corporation as at December 31, 2022;

"**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 Energy North America Canada Partnership;

"**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 aggregate gross proceeds of approximately $30 million completed on February 11, 2020 as part of the Private Placements and Reconstitution of Management;

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

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

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

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

"**Unit Private Placement**" means the private placement of 21,739,130 Units at a price of $0.92 per Unit for aggregate gross 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.

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, 2022.

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, but are not limited to, those relating to: Headwater's focus, business plan and business strategy; 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 ability to deliver responsibly produced energy and offer long-term sustainable value to its Shareholders; 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; the availability of applicable exemptions in respect of the Corporation's operations in the Sussex region of New Brunswick; Headwater's expectations that interest or other funding costs will not make further development of its reserves uneconomic; 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 plans to continue delineation activities in 2023 and proactively work to secure new prospective opportunities; Headwater's expectations regarding its waterflood program, including but not limited to, the timing and effectiveness thereof; Headwater's commitment to returning excess free cash to Shareholders; 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 intention to test the ERP in 2023 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 2023 capital expenditure program and results thereof; timing and amount of capital expenditures and implementation thereof; 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 the Corporation's reserves; future crude oil, NGLs and natural gas production levels; drilling plans; anticipated future crude oil, natural gas and NGLs prices and currency, exchange, inflation and interest rates; the tax horizon of Headwater; future supply of 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 compliance with the provisions of applicable tax legislation; Headwater's dividend policy and the future payment of dividends; potential effects of regulatory regimes; and treatment under government regulatory and taxation regimes. All statements relating to "reserves" are also 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; factors that could result in the change in timing or cancellation of future development of Headwater's assets; 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, capacity 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 and interest rate fluctuations, our ability to pay dividends and our dividend policy, imprecision of reserve estimates, environmental risks, competition from other producers, risks of pandemics and impacts resulting therefrom, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, our 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 time and capital 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 9, 2023 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.

NON-GAAP FINANCIAL MEASURES

In this Annual Information Form, the Corporation uses the term "capital expenditures". Capital expenditures is a non-GAAP financial measure that does not have a standardized meaning prescribed under International Financial Reporting Standards ("**IFRS**") and therefore may not be comparable to a similar measure presented by other entities. Management utilizes capital expenditures to measure total cash capital expenditures incurred in the period. Capital expenditures represents capital expenditures – exploration and evaluation and capital expenditures – property, plant and equipment in the statement of cash flows in the Corporation's audited annual financial statements netted by the government grant received by the Corporation towards such expenditures. This measure should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. For further information, readers should refer to the section entitled "*Non-GAAP and Other Financial Measures*" located in the management's discussion and analysis of the Corporation for the year ended December 31, 2022, available on the Corporation's SEDAR profile at www.sedar.com.

	Year ended December 31,	
	2022 ($M)	**2021 ($M)**
Cash flows used in investing activities	232,056	109,127
Proceeds from government grant	1,988	-
Restricted cash	-	1,477
Change in non-cash working capital	14,879	29,785
Government grant	(4,428)	-
Capital expenditures	244,495	140,389

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 1400, 215 – 9th Avenue S.W., Calgary, Alberta T2P 1K3 and its registered office is located at 2400, 525 – 8th Avenue S.W., Calgary, Alberta T2P 1G1.

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

GENERAL DEVELOPMENT OF THE BUSINESS

History and Development

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

Recent Developments

Year 2022

Credit Facility

In December 2022, Headwater executed a $100 million Credit Facility agreement comprised of a $20.0 million operating facility and an $80.0 million syndicated facility. As at December 31, 2022, the Corporation had not drawn on the Credit Facility.

ESG Report

On November 15, 2022, Headwater published and posted to its website its inaugural 2022 environmental, social and governance report (the "**ESG Report**") highlighting its ability to deliver responsibly produced energy and offer long-term sustainable value to its Shareholders.

Quarterly Dividend

On November 3, 2022, in conjunction with the Corporation's continued success, Headwater announced its inaugural quarterly cash dividend of $0.10 per Common Share ($0.40 per Common Share annualized). The first dividend was payable on January 16, 2023 to Shareholders of record at the close of business on December 30, 2022. See "*Dividend Policy*" for more information.

Capital Budget

On November 3, 2022, the Board approved Headwater's initial 2023 capital budget of $200 million.

Board Changes

On May 12, 2022, Elena Dumitrascu was elected to the Board.

Emissions Reduction Fund

During 2022, Headwater was approved for total funding of up to $18.5 million from Natural Resources Canada associated with the Emissions Reduction Fund ("**ERF**") program for infrastructure spending related to the elimination of venting and flaring of methane rich natural gas in the Corporation's core area of Marten Hills. As at the date of this Annual Information Form, Headwater has received $11.0 million of the approved funding from the ERF program.

Combined Operations

Headwater achieved corporate annual average production of 12,841 BOE/d, consisting of 11,411 Bbls/d of heavy crude oil, 8.2 MMcf/d of natural gas and 57 Bbls/d of natural gas liquids in 2022.

Marten Hills Operations and Entrance into the Greater Peavine and West Nipisi Areas

Headwater spent approximately $245 million on capital expenditures in 2022 and achieved annual average production of 12,256 BOE/d, consisting of 11,411 Bbls/d of heavy crude oil, 4.7 MMcf/d of natural gas and 54 Bbls/d of natural gas liquids. The Corporation drilled 107 (107.0 net) wells including 97 (97.0 net) crude oil wells, 9 (9.0 net) source wells/stratigraphic tests and 1 (1.0 net) junked and abandoned well in 2022. Of the 97 crude oil wells drilled, 94 were drilled in the Marten Hills area, of which 18 were subsequently converted to injection as part of the Corporation's enhanced oil recovery activities. In addition, Headwater completed construction of its 15,000 Bbls/d oil processing facility in Marten Hills which was commissioned in March 2022.

In May 2022, Headwater announced it had accumulated a significant land position prospective for heavy oil in the Falher/Clearwater plays in Greater Peavine and West Nipisi, establishing the Corporation's next exploration focus areas. As at December 31, 2022, Headwater had added 118 net sections of unburdened land in the Greater Peavine and West Nipisi areas and had drilled and completed 3 (3.0 net) crude oil wells in West Nipisi.

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 2022 and resumed production in late November 2022. Headwater's natural gas production averaged 3.5 MMcf/d and its natural gas liquids production averaged 3 Bbls/d in 2022 from the McCully Field. No development operations occurred in 2022 as the lifting of the fracking moratorium in the Sussex region remained uncertain.

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 in 2021.

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 also drilled 58 (58.0 net) wells including 51 (51.0 net) crude oil wells and 7 (7.0 net) source wells/stratigraphic tests in the Marten Hills area in 2021. 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.

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 in 2021 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 Cenovus Warrants, Cenovus held approximately 7% of the outstanding Common Shares at that time.

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, which were subsequently fully-exercised on December 23, 2021.

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 Bbls/d 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 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 retained the right, after twelve months from December 2, 2020 and provided the 20-day volume weighted average trading price of the Common Shares exceeded $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.

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.

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 May 2022, Headwater announced it had accumulated a significant land position prospective for heavy oil in the Falher/Clearwater plays in the Greater Peavine and West Nipisi areas, establishing the Corporation's next exploration focus areas. 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, Greater Peavine and West Nipisi areas 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:

- ***Maintain positive working capital.*** 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, 2022, Headwater had working capital of approximately $109 million and no bank debt.

- ***Continue adding incremental prospects through strategic land acquisitions and accretive mergers and acquisitions.*** The Corporation spent approximately $33 million in 2022 on unburdened land in Greater Peavine and West Nipisi, establishing Headwater's next exploration focus areas. Headwater drilled its first 3 successful exploration wells in the fourth quarter of 2022 in West Nipisi and plans to continue these delineation activities into 2023. Headwater explores for new oil and natural gas plays on its undeveloped land base and proactively works to secure other new and prospective opportunities.

- ***Continue to implement secondary recovery reducing decline rates and providing long-term return of capital stability.*** Headwater expects to have 65% of the Marten Hills core area under waterflood by the end of 2023 and anticipates that the entire 10 sections in the core area will be under waterflood in 2024. Headwater is expecting to complete its first waterflood pilot in the Marten Hills West area by the end of the first quarter of 2023.

- ***Sustained Shareholder Returns.*** On November 3, 2022, in conjunction with the Corporation's continued success, Headwater announced its inaugural quarterly cash dividend of $0.10 per Common Share ($0.40 per Common Share annualized). The first dividend was paid on January 16, 2023 to Shareholders of record at the close of business on December 30, 2022. Headwater remains committed to returning excess free cash to Shareholders.

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, 2022, the Corporation had 28 employees and 6 consultants in the Calgary head office, 1 employee in Halifax, 3 employees in the field in New Brunswick, 16 consultants in the field in Alberta 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, 2022, see the Corporation's audited financial statements for the year ended December 31, 2022, which have been filed on SEDAR and may be viewed under the Corporation's profile at 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.

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 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.

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 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, 2022 and subsequent to December 31, 2022, see the Corporation's audited financial statements for the year ended December 31, 2022, which have been filed on SEDAR and may be viewed under the Corporation's profile at www.sedar.com. See "*Risk Factors – Prices, Markets and Marketing*".

Cyclical and Seasonal Nature of Industry

Headwater's operational results and financial condition are dependent on the prices received for 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 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 uses minimal fresh water in its drilling operations by utilizing oil-based mud. The oil-based mud is recycled and reused within the program which results in a reduced environmental footprint and reduced costs for the Corporation. Headwater's Marten Hills waterflood utilizes saline and produced water, without any fresh water usage.

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, 2022, Headwater's liability management rating ("**LMR**") was 28 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. 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 incurs costs and utilizes resources in cleaning up such spills. In 2022, the Corporation did not have any material spills or releases.

Health, Safety, Environmental and Social Policies

Under its mandate, the Board oversees the health, safety and environmental compliance and protection by the Corporation; however, it has delegated certain of its responsibilities for the oversight of health, safety and environmental matters to the Reserves and Safety Committee, which is comprised of independent directors of the Corporation. In addition to the oversight of Headwater's environmental and safety practices by the Board and the Reserves and Safety Committee, 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 Corporation's 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 with 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 2023 with exercises and drills to ensure its effectiveness and its procedures are revised to ensure the Corporation is adhering to the highest industry standards.

Under its mandate, the Reserves and Safety Committee oversees the health, safety and environmental compliance and protection by the Corporation. As part of this mandate, the Reserves and Safety Committee requires management to provide a report at each quarterly Reserves and Safety Committee meeting outlining any environmental or safety incidents that occurred or areas of concern that have arisen since the previous quarterly Reserves and Safety Committee meeting and considers whether any changes should be implemented. The Reserves and Safety Committee and the Board also receive periodic updates from management on implemented or proposed legislative or regulatory changes that may affect the Corporation's operations. Under it mandate, the Reserves and Safety Committee provides reports and make recommendations to the Board as determined necessary on environment, health and safety that are relevant to the Corporation. In addition, periodically, the Reserves and Safety Committee and/or 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 natural gas information set forth below (the "**Reserves Data**") is based upon the evaluation by GLJ with an effective date of December 31, 2022, contained in the GLJ Report dated February 24, 2023.

Disclosure of Reserves Data

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

Headwater's reserves are located in the Marten Hills and West Nipisi areas 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, 2022
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)
PROVED										
Developed Producing	20,750	19,337	776	759	12,937	9,833	89	65	16,614	13,248
Developed Non-Producing	51	44	1,500	1,468	221	186	1	-	480	439
Undeveloped	145	126	-	-	4,006	3,365	1	1	4,032	3,387
TOTAL PROVED	**20,946**	**19,507**	**2,276**	**2,227**	**17,164**	**13,385**	**91**	**67**	**21,126**	**17,074**
PROBABLE										
Developed Producing	7,656	7,039	258	252	5,431	4,148	44	32	6,793	5,395
Developed Non-Producing	59	49	500	489	145	108	1	-	239	198
Undeveloped	1,739	1,512	-	-	5,846	4,935	1	1	6,137	5,188
TOTAL PROBABLE	**9,453**	**8,599**	**758**	**741**	**11,422**	**9,191**	**45**	**33**	**13,169**	**10,781**
TOTAL PROVED PLUS PROBABLE	**30,399**	**28,106**	**3,034**	**2,969**	**28,587**	**22,576**	**136**	**100**	**34,295**	**27,855**

Note:

(1) Columns may not add due to rounding.

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
as at December 31, 2022
FORECAST PRICES AND COSTS[1]

	Before Income Tax Discounted at (%/year)					After Income Taxes Discounted at (%/year)[2]				
RESERVES CATEGORY	0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)	0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)
PROVED										
Developed Producing	602,841	542,500	490,424	448,535	414,689	518,371	466,231	420,704	384,152	354,730
Developed Non-Producing	19,856	16,687	14,333	12,572	11,222	15,297	12,803	10,958	9,590	8,551
Undeveloped	96,883	80,232	67,182	56,705	48,181	73,343	59,446	48,609	39,945	32,928
TOTAL PROVED	**719,579**	**639,419**	**571,939**	**517,812**	**474,092**	**607,011**	**538,480**	**480,271**	**433,686**	**396,209**
PROBABLE										
Developed Producing	256,752	182,352	135,918	105,713	85,070	198,840	140,870	104,770	81,391	65,452
Developed Non-Producing	14,069	10,007	7,551	5,968	4,886	10,365	7,412	5,620	4,463	3,668
Undeveloped	192,481	146,602	114,395	91,194	74,010	147,910	111,729	86,198	67,792	54,180
TOTAL PROBABLE	**463,302**	**338,961**	**257,863**	**202,875**	**163,966**	**357,115**	**260,011**	**196,588**	**153,646**	**123,301**
TOTAL PROVED PLUS PROBABLE	**1,182,881**	**978,380**	**829,802**	**720,687**	**638,058**	**964,126**	**798,491**	**676,859**	**587,332**	**519,510**

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, 2022. 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, 2022
FORECAST PRICES AND COSTS[1]

RESERVES CATEGORY	REVENUE ($000s)	ROYALTIES ($000s)	OPERATING COSTS ($000s)	DEVELOPMENT COSTS ($000s)	ABANDONMENT AND RECLAMATION COSTS[2] ($000s)	FUTURE NET REVENUE BEFORE INCOME TAXES ($000s)	FUTURE INCOME TAXES ($000s)	FUTURE NET REVENUE AFTER INCOME TAXES ($000s)
Proved Reserves	1,480,513	282,975	321,460	94,826	61,673	719,579	112,568	607,011
Proved Plus Probable Reserves	2,474,125	461,280	594,915	159,376	75,672	1,182,881	218,756	964,126

Notes:

(1) The estimated values of future net revenues disclosed do not represent fair market value.
(2) For more information, see "*Statement of Reserves Data and Other Oil and Gas Information – Significant Factors or Uncertainties – Additional Information about Abandonment and Reclamation Cost*s".

FUTURE NET REVENUE
BY PRODUCTION TYPE
as of December 31, 2022
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION TYPE	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000s)[2]	UNIT VALUE[3] ($)/BOE
Proved Reserves	Conventional Natural Gas[1]	61,778	26.47
	Shale Gas[1]	9,620	25.86
	Heavy Crude Oil[1]	500,540	34.84
	Total[2]	**571,939**	**33.50**
Proved Plus Probable Reserves	Conventional Natural Gas[1]	74,016	24.47
	Shale Gas[1]	13,867	27.97
	Heavy Crude Oil[1]	741,920	30.49
	Total[2]	**829,802**	**29.79**

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, 2022, 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, 2023.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS[1]
as of December 31, 2022
FORECAST PRICES AND COSTS

	Crude Oil				Edmonton Liquids Prices	
Year	**WTI Cushing Oklahoma (US$/Bbl)**	**Light Sweet Crude Oil at Edmonton 40º API (Cdn$/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[4]						
2023	80.33	103.77	77.46	76.54	106.22	53.88
2024	78.50	97.74	78.65	77.75	101.35	52.67
2025	76.95	95.27	78.42	77.54	98.94	51.42
2026	77.61	95.58	80.94	80.07	100.19	51.61
2027	79.16	97.07	82.78	81.89	101.74	52.39
2028	80.75	99.01	84.92	84.02	103.78	53.44
2029	82.36	100.99	86.65	85.73	105.85	54.51
2030	84.01	103.01	88.38	87.44	107.97	55.60
2031	85.69	105.07	90.15	89.20	110.13	56.71
2032	87.40	106.69	92.08	91.11	112.33	57.56
2033	89.15	108.83	93.92	92.93	114.58	58.71
Thereafter escalation rate of 2.0%						

	Natural Gas					
Year	**Natural Gas AECO-C Spot (Cdn$/MMBtu)**	**NYMEX Henry Hub (US$/MMBTU)**	**AGT Gas Price (US$/MMbtu)**	**McCully Gas Price[2] (Cdn$/Mcf)**	**Inflation Rate %/Year**	**Exchange Rate [3] (US$/Cdn$)**
Forecast[4]						
2023	4.23	4.74	7.92	14.68	0.0	0.75
2024	4.40	4.50	6.38	11.93	2.3	0.77
2025	4.21	4.31	6.19	11.53	2.0	0.77
2026	4.27	4.40	6.28	9.99	2.0	0.77
2027	4.34	4.49	6.37	10.12	2.0	0.78
2028	4.43	4.58	6.46	10.28	2.0	0.78
2029	4.51	4.67	6.55	10.44	2.0	0.78
2030	4.60	4.76	6.64	10.60	2.0	0.78
2031	4.69	4.86	6.74	10.78	2.0	0.78
2032	4.79	4.95	6.83	10.94	2.0	0.78
2033	4.89	5.05	6.96	11.15	2.0	0.78
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 2023 – 2025 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 2025, 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, 2022.

The weighted average historical prices realized, before financial derivative contracts, by the Corporation for the year ended December 31, 2022, were $10.60/Mcf for natural gas, $91.29/Bbl for NGLs and $101.59/Bbl for heavy crude oil. The weighted average historical price of heavy crude oil net of costs to blend was $94.79/Bbl.

Reconciliation of Changes in Reserves

The following table sets out the reconciliation of the gross reserves of the Corporation as at December 31, 2022 as compared to December 31, 2021:

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

FACTORS	Conventional Natural Gas Gross Proved (MMcf)	Conventional Natural Gas Gross Probable (MMcf)	Conventional Natural Gas Gross Proved Plus Probable (MMcf)	Shale Natural Gas Gross Proved (MMcf)	Shale Natural Gas Gross Probable (MMcf)	Shale Natural Gas Gross Proved Plus Probable (MMcf)	Heavy Crude Oil Gross Proved (MBbl)	Heavy Crude Oil Gross Probable (MBbl)	Heavy Crude Oil Gross Proved Plus Probable (MBbl)
December 31, 2021(1)	**20,224**	**6,982**	**27,206**	**1,804**	**507**	**2,311**	**11,665**	**6,697**	**18,362**
Extensions and Improved Recovery(3)	3,113	2,803	5,915	-	-	-	9,195	6,690	15,885
Technical Revisions(4)	508	(496)	12	472	222	694	443	(1,981)	(1,538)
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	109	165	274	-	29	29	27	16	43
Production	(3,008)	-	(3,008)	-	-	-	(4,165)	-	(4,165)
December 31, 2022(2)	**20,946**	**9,453**	**30,399**	**2,276**	**758**	**3,034**	**17,164**	**11,422**	**28,587**

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

FACTORS	Natural Gas Liquids Gross Proved (MBbl)	Natural Gas Liquids Gross Probable (MBbl)	Natural Gas Liquids Gross Proved Plus Probable (MBbl)	Total Oil Equivalent Gross Proved (MBOE)	Total Oil Equivalent Gross Probable (MBOE)	Total Oil Equivalent Gross Proved Plus Probable (MBOE)
December 31, 2021(1)	**327**	**182**	**509**	**15,663**	**8,126**	**23,790**
Extensions and Improved Recovery(3)	(22)	(23)	(44)	9,692	7,135	16,827
Technical Revisions(4)	(195)	(114)	(308)	412	(2,141)	(1,729)
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	45	49	94
Production	(21)	-	(21)	(4,687)	-	(4,687)
December 31, 2022(2)	**91**	**45**	**136**	**21,125**	**13,170**	**34,295**

Notes:

(1) As evaluated by GLJ as at December 31, 2021, 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 2022 capital expenditure program. Improved recovery is a result of additional reserves related to enhanced oil recovery activities.
(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

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 and West Nipisi areas. 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*".

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, 2022, 2021 and 2020 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
2020	3,099	3,099	-	-	3,673	3,673	128	128	4,317	4,317
2021	1,765	1,995	-	-	4,721	5,226	107	121	5,123	5,680
2022	**102**	**145**	**-**	**-**	**2,380**	**4,006**	**1**	**1**	**2,397**	**4,032**

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.

GLJ has assigned 4.0 MBOE of proved undeveloped reserves in the GLJ Report under forecast prices and costs, together with $86.8 million of associated undiscounted future capital expenditures with substantially all scheduled to be developed in the first two forecast years.

Probable 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
2020	1,507	1,507	-	-	1,637	1,637	62	62	1,950	1,950
2021	1,073	1,168	-	-	2,958	3,154	65	71	3,202	3,420
2022	**1,682**	**1,739**	**-**	**-**	**5,170**	**5,846**	**1**	**1**	**5,451**	**6,137**

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.

GLJ has assigned 6.1 MBOE of probable undeveloped reserves in the GLJ Report under forecast prices and costs, together with $64.4 million of associated undiscounted future capital expenditures with substantially all scheduled to be developed in the first two forecast years.

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 existing wells (including inactive wells) and related facilities and infrastructure as of December 31, 2022, is approximately $43 million on an undiscounted, uninflated basis. The abandonment and reclamation costs in New Brunswick include 32.0 net wells, the gas processing plant and transmission pipeline and in Alberta include 186.0 net wells (142.0 net oil and gas wells (producing and non-producing), 26.0 net injection wells and 18.0 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 on all existing wells with reserves, inactive wells with no reserves assigned and related facilities and infrastructure 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 $76 million (undiscounted) and $13 million (10% discounted) 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, 2022 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.

Future Development Costs

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

	Forecast Prices and Costs	
Year	**Proved Reserves ($M)**	**Proved Plus Probable Reserves ($M)**
2023	58,383	85,583
2024	33,249	70,470
2025	-	-
2026	-	-
2027	3,194	-
Thereafter	-	3,323
Total: Undiscounted	94,826	159,376
Discounted 10%	86,619	144,004

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 2023 include anticipated costs for exploration and development activities in Alberta of $200 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 2023 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, the Credit Facility or debt or equity financings, if necessary. Headwater may also consider issuing Common Shares or other securities as consideration for future acquisitions.

Headwater's 2023 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 2024 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

Alberta – Marten Hills

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, 2022, the Corporation's interests in the Marten Hills area consisted of approximately 203,423 net acres.

The Clearwater formation in the Marten Hills area is characterized as a conventional reservoir, with variability throughout, but in general is an oil-bearing formation of approximately 15 meters in thickness on average. 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 in Marten Hills (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 Marten Hills assets in 2022 was 12,256 BOE/d (11,411 Bbls/d of heavy crude oil, 4.7 MMcf/d of natural gas and 54 Bbls/d of natural gas liquids). 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 and quality of WCS.

As at December 31, 2022, Headwater's Marten Hills assets included 132.0 net producing oil wells, 26.0 net injection wells, 5.0 net non-producing oil wells, 2.0 net non-producing natural gas wells, 18.0 net observation/water source/stratigraphic test wells, 20.0 multi-well batteries, a joint gas processing facility and an oil processing facility. The Corporation drilled 104.0 net wells in the Marten Hills area, including 94.0 net crude oil wells, 9.0 net source wells/stratigraphic tests and 1.0 net junked and abandoned well, in 2022.

The GLJ Report assigned gross proved plus probable reserves of 27,706 MMBbl of heavy oil, 11,965 MMcf of conventional natural gas and 116 MBbl of natural gas liquids to the Corporation's properties in the Marten Hills area as at December 31, 2022.

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, 2022, which have been filed on SEDAR and may be viewed under the Corporation's profile at 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 Corporation's Alberta 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.

New Brunswick – 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); and
- 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.

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, 2022 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.

	Oil Wells				**Natural Gas Wells**			
	Producing		**Non-Producing**		**Producing**		**Non-Producing**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
New Brunswick	-	-	1.0	1.0	32.0	24.0	8.0	7.0
Alberta	135.0	135.0	5.0	5.0	-	-	2.0	2.0
Total	**135.0**	**135.0**	**6.0**	**6.0**	**32.0**	**24.0**	**10.0**	**9.0**

Note:

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

Properties with no Attributed Reserves

The following table sets out the developed and undeveloped land holdings of Headwater as at December 31, 2022.

	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	15,523	15,523	-	-	15,523	15,523
Alberta	265,183	265,183	17,920	17,920	283,103	283,103
Total	**490,529**	**472,262**	**25,038**	**23,258**	**515,567**	**495,520**

No rights to explore, develop and exploit the Corporation's undeveloped land holdings are expected to expire before December 31, 2023.

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. Headwater strives to mitigate this credit risk by entering into contracts with 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, 2022, 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 $291 million of tax pools available, consisting primarily of Canadian Development Expense, Canadian Oil and Gas Property Expense and Undepreciated Capital Cost.

Headwater recorded approximately $14.4 million of current income tax expense for the year ended December 31, 2022. The Corporation was not required to pay income taxes in prior years as Headwater had sufficient tax deductions available to shelter taxable income. For more information, see Note 11 "Income Taxes" in Corporation's audited financial statements for the year ended December 31, 2022, 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, 2022, 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 $245 million in Alberta during the year ended December 31, 2022. See "*Statement of Reserves Data and Other Oil and Gas Information – Description of Principal Properties*".

On November 3, 2022, the Board approved a 2023 capital budget of $200 million. The capital budget is expected to result in 2023 annual average production of 18,000 BOE/d (16,390 Bbls/d of heavy crude oil, 9.3 MMcf/d of natural gas and 60 Bbls/d of natural gas liquids). See "*Statement of Reserves Data and Other Oil and Gas Information – Description of Principal Properties*".

Costs Incurred

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

($ thousands)	Year ended December 31, 2022
Property Acquisition	
Proved Properties	-
Unproved Properties	31,652
Exploration Costs(1)	48,013
Development Costs(2)	164,830
Dispositions	-
Total capital expenditures	**244,495**

Notes:

(1) Includes seismic costs and costs associated with drilling, completing and equipping the Corporation's exploration wells.
(2) Includes capitalized general and administrative expenses and a recovery to capital expenditures recognized with respect to ERF funding received.

Production Estimates

The following table sets out the volume of working interest production estimated for the year ended December 31, 2023, 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*".

	Conventional Natural Gas (Mcf/d)	Shale Natural Gas (Mcf/d)	Heavy Crude Oil (Bbls/d)	Natural Gas Liquids (Bbls/d)	Total (BOE/d)
Proved					
Developed Producing	6,863	57	11,423	57	12,634
Developed Non-Producing	62	-	216	1	227
Undeveloped	66	-	1,718	1	1,730
Total Proved	6,992	57	13,358	59	14,591
Total Probable	235	8	751	1	793
Total Proved Plus Probable	**7,227**	**65**	**14,109**	**60**	**15,384**

The gross production estimated for the year ended December 31, 2023 reflected in the estimate of future net revenue for gross P+P Reserves from the Corporation's Alberta properties is 14,109 Bbls/d of heavy crude oil, 5.1 MMcf/d of natural gas and 58 Bbls/d of natural gas liquids. The gross production estimated for the year ended December 31, 2023, reflected in the estimate of future net revenue for the Corporation's gross P+P Reserves from the McCully Field in New Brunswick is 2.2 MMcf/d of natural gas and 2 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 2022				Year Ended
	Mar. 31	June 30	Sept. 30	Dec. 31	Dec. 31, 2022
Average Daily Production(1)					
Natural Gas (MMcf/d)	10.8	6.4	4.3	11.5	8.2
NGLs (Bbls/d)	7	66	55	99	57
Heavy Crude Oil (Bbls/d)	10,602	10,637	10,842	13,536	11,411
Combined (BOE/d)	12,414	11,772	11,612	15,546	12,841
Average Net Sales Prices Received(2)					
Natural Gas ($/Mcf)	15.65	7.28	4.23	10.15	10.60
NGLs ($/Bbl)	108.57	113.61	95.54	73.02	91.29
Heavy Crude Oil ($/Bbl)	98.80	121.49	92.35	73.10	94.79
Combined ($/BOE)	98.09	114.34	88.27	71.60	91.44
Royalties Paid(4)					
Natural Gas ($/Mcf)	0.82	0.58	1.13	0.65	0.76

	Quarter Ended 2022				Year Ended
	Mar. 31	June 30	Sept. 30	Dec. 31	Dec. 31, 2022
Natural gas liquids ($/Bbl)	-	35.47	34.12	22.58	28.39
Heavy Crude Oil ($/Bbl)	16.83	25.84	22.87	14.80	19.76
Combined ($/BOE)	15.09	23.85	21.93	13.51	18.17
Production Costs(3)(4)					
Natural Gas ($/Mcf)	0.68	0.75	0.98	0.42	0.64
Natural gas liquids ($/Bbl)	-	-	-	-	-
Heavy Crude Oil ($/Bbl)	6.06	5.81	5.99	6.82	6.21
Combined ($/BOE)	5.77	5.66	5.95	6.25	5.93
Transportation Costs(4)					
Natural Gas ($/Mcf)	-	-	-	0.36	0.13
Natural gas liquids ($/Bbl)	-	-	-	-	-
Heavy Crude Oil ($/Bbl)	5.74	4.50	4.22	4.53	4.73
Combined ($/BOE)	4.90	4.07	3.94	4.21	4.28
Netback(5)					
Natural Gas ($/Mcf)	14.15	5.94	2.13	8.71	9.07
Natural gas liquids ($/Bbl)	108.57	78.15	61.42	50.44	62.89
Heavy Crude Oil ($/Bbl)	70.16	85.34	59.27	46.96	64.10
Combined ($/BOE)	72.33	80.76	56.44	47.63	63.06

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 production costs and transportation costs for NGLs as Headwater only had nominal sales of NGLs in 2022 and therefore information is included in the combined BOE.
(5) Calculated using average sales volumes in the period.

In 2022, the Corporation derived the majority of its production from properties in Alberta. The gross working interest production from Alberta in 2022 was 11,411 Bbls/d of heavy oil, 4.7 MMcf/d of natural gas and 54 Bbls/d of natural gas liquids. The McCully Field contributed 3.5 MMcf/d of natural gas and 3 Bbls/d of NGLs to the Corporation's total production in 2022.

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, P.Eng Alberta, Canada	Chairman, Chief Executive Officer and a Director (since March 4, 2020)
Jason Jaskela, P.Eng 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)
Brad Christman Alberta, Canada	Vice President, Production (since April 1, 2020)
Terry Danku, P.Eng Alberta, Canada	Vice President, Engineering (since March 4, 2020)

Name and Place of Residence	Office Held
Jon Grimwood Alberta, Canada	Vice President, Exploration (since March 4, 2020)
Scott Rideout Alberta, Canada	Vice President, Land (since March 4, 2020)
Elena Dumitrascu Alberta, Canada	Director (since May 12, 2022)
Chandra Henry(1)(2), CPA, CFA, ICD.D Alberta, Canada	Director (since March 4, 2020)
Phillip Knoll(3), P.Eng Alberta, Canada	Director (since September 21, 2010)
Stephen Larke(2), B. Comm, CFA, ICD.D Alberta, Canada	Director (since March 4, 2020)
Kevin Olson(1)(3) Alberta, Canada	Lead Independent Director (since March 4, 2020)
David Pearce(2)(3) Alberta, Canada	Director (since March 4, 2020)
Kam Sandhar(1) 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 and Safety 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 9, 2023, the directors and executive officers of Headwater, as a group, beneficially owned or controlled or directed, directly or indirectly, 19,450,316 Common Shares or approximately 8.3% 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 23 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 and serves on the board of directors of Lycos Energy Inc.

Terry Danku, Vice President, Engineering

Mr. Danku is a professional engineer with over 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 from the University of Saskatchewan 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 Petroleums Ltd. in 1997 and held positions of increasing responsibility at Burlington Resources Canada Ltd., Rider Resources Ltd. and Galleon Energy Inc. Mr. Grimwood earned a Bachelor of Science from Brandon University, a Masters Degree in Earth Sciences from the University of Waterloo and is a Registered Member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA).

Scott Rideout, Vice President, Land

Mr. Rideout is a land professional with over 20 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 has more than 25 years of progressive experience in finance, treasury, risk, taxation and operations within the financial services industry crossing multiple geographic and business segments. She is currently the Chief Financial Officer and Chief Compliance Officer of Longbow Capital Inc., a private equity firm investing in the North American energy markets. Prior to her role with Longbow, Ms. Henry held various senior finance positions, including Chief Financial Officer of WestBlock Inc. (2018-19), Director of Finance for GMP Securities L.P. (2016-17) and Chief Financial Officer for FirstEnergy Capital Corp. (2001-16). 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) Credential Holder. Ms. Henry currently sits on the board of directors of Whitecap Resources Inc., a public oil and natural gas company (for whom she serves on the Audit Committee and Sustainability and Advocacy Committee) and was previously a director of Bonavista Energy Corporation and Pengrowth Energy Corporation.

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 was 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 30 years of industry experience and currently serves on the board of directors of Lycos Energy Inc. 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 formerly a director of Raging River (March 2012) until the sale to Baytex in August 2018. Mr. Pearce was also with Northrock Resources Ltd. from June 1999 to January 2008 where he held several senior officer positions, including 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.

Elena Dumitrascu, Director

Ms. Dumitrascu is a Co-Founder and has been the Chief Technology Officer of TerraHub Technologies Inc. since 2018. Since 2019, Ms. Dumitrascu, has served as a Blockchain Instructor at the University of Calgary. Ms. Dumitrascu has over 20 years of entrepreneurial experience in the technology industry playing a pivotal role in founding companies and helping companies grow and achieve success, including as Vice-President Strategic Partnerships at Cortex Business Solutions from 2015 through 2018 and as Founder and Chief Executive Officer of Caledonia Solutions Inc. from 2009 through 2015. Ms. Dumitrascu has a Bachelor of Sciences degree in Computer Science from the University of Windsor.

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 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 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.

On December 8, 2021, Kaisen Energy Corp. ("**Kaisen**"), of which David Pearce was a director, 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 provided Kaisen the opportunity to prepare and file a plan of arrangement (the "**Plan**") under the CCAA for the consideration of its creditors and other stakeholders. Affected creditors voted in favor of the Plan on January 27, 2022, and a Plan Sanction Order was issued by the Court on February 1, 2022. The Plan was fully implemented by the Monitor as of March 16, 2022, which resulted in Kaisen successfully exiting CCAA proceedings.

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 its knowledge, the Corporation is not aware of the existence of any material conflicts of interest between any of their directors and officers as of the date hereof.

DIVIDEND POLICY

Cash dividends are declared and paid following the end of each fiscal quarter to Shareholders of record on the last business day of each such fiscal quarter or such other date as determined from time to time by the Board. Unless otherwise specified, all dividends paid or to be paid by Headwater are designated as "eligible dividends" under the Tax Act.

The following quarterly cash dividend on the Common Shares was declared and paid by Headwater for the period indicated:

RECORD DATE	PAYMENT DATE	CASH DIVIDEND PER COMMON SHARE
December 31, 2022	January 16, 2023	$0.10

On March 9, 2023, the Board approved a quarterly cash dividend of $0.10 per Common Share to be paid on April 17, 2023 to Shareholders of record at the close of business on March 31, 2023.

Headwater will monitor the impact of all issues affecting its business and the necessity to adjust its quarterly dividends and capital programs as conditions evolve. During periods of volatile commodity prices, Headwater may reduce or suspend the dividend. See "*Risk Factors – Dividends*".

Headwater's long-term objective is to set its dividend policy at prudent levels while withholding sufficient funds to finance capital expenditures required to grow its current production base. This in turn, is expected to provide a stronger base of cash flow from operating activities leading to consistent dividends into the future. Headwater's dividend policy is reviewed quarterly and is based on a number of factors, including but not limited to, commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates, available investment opportunities and the satisfaction of the liquidity and solvency tests imposed by the ABCA for the declaration and payment of dividends.

The payment of dividends by a corporation is governed by the liquidity and insolvency tests described in the ABCA. Pursuant to the ABCA, after the payment of a dividend, the Corporation must be able to pay its liabilities as they become due and the realizable value of its assets must be greater than its liabilities and the legal stated capital of its outstanding securities. All of the Common Shares will be entitled to an equal share in any dividends declared and paid.

Cash dividends are not guaranteed. Historical cash dividends may not be reflective of future cash dividends, which will be subject to review by the Board taking into account our prevailing financial circumstances at the relevant time. Although Headwater intends to make dividends of its available cash to Shareholders, these cash dividends may be reduced or suspended. Actual dividend amounts paid will depend on numerous factors and conditions existing from time to time, including but not limited to, commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates, available investment opportunities and the satisfaction of the liquidity and solvency tests imposed by the ABCA for the declaration and payment of dividends. See "*Risk Factors – Dividends*".

DESCRIPTION OF SHARE CAPITAL

Common Shares

The authorized share capital of the Corporation includes an unlimited number of Common Shares without nominal or par value of which, as at March 9, 2023, 234,043,686 Common Shares are issued and outstanding as fully paid and non-assessable. In addition, the Corporation has stock options to purchase 5,867,183 Common Shares, 179,184 restricted share units and 834,891 performance share units outstanding as of March 9, 2023.

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 Common Shares trade on the TSX under the trading symbol "HWX". The following table sets out the high and low trading prices and aggregate volume of trading of the Common Shares on the TSX for the periods indicated:

Price Range and Trading Volume

Period	High ($)	Low ($)	Volume
2022			
January	7.29	5.26	26,506,955
February	7.66	6.75	25,464,072
March	7.62	5.87	44,436,494
April	7.65	6.48	22,616,521
May	7.64	6.17	25,549,580
June	8.18	5.28	29,979,911
July	6.27	4.79	17,546,685
August	6.42	5.35	17,567,432
September	6.43	4.96	21,238,382
October	7.285	5.45	18,851,457
November	7.88	5.92	23,046,427
December	6.725	5.52	16,773,994
2023			
January	6.56	5.23	17,548,540
February	6.64	5.82	16,391,075
March (1 – 8)	6.445	5.91	3,527,634

Prior Sales

During the year ended December 31, 2022, Headwater issued a total of 179,004 restricted share units and 838,371 performance share units pursuant to the Corporation's performance and restricted award plan. On the payment date of such awards, the Corporation has the sole discretion as to whether the awards shall be paid in cash, Common Shares from treasury or Common Shares purchased on the TSX. See Notes 9 and 10 to our financial statements for the year ended December 31, 2022 for additional information.

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.

Our results of operations and financial condition are dependent upon the prices that we receive for the oil, NGLs and natural gas that we sell. Historically, the oil, NGL and natural gas markets have been volatile and are likely to continue to be volatile in the future. Oil, NGL and natural gas prices have fluctuated widely during recent years and are subject to fluctuations in response to changes in supply, demand, market uncertainty and other factors that are beyond our control. These factors include, but are not limited to:

- the impact of regional and/or global health related events, such as the ongoing COVID-19 pandemic, on economic activity levels and energy demand;
- global energy policy, including the ability of OPEC+ (and in particular the Kingdom of Saudi Arabia) and other oil and natural gas exporting nations (and in particular Russia) to set and maintain production levels and influence prices for oil;
- the limitations on the ability of Western Canadian energy producers to export oil, NGLs and natural gas to U.S. markets and other world markets and the resulting discount that Western Canadian energy producers may receive for their products as compared to U.S. and international benchmark commodity prices;
- the availability of transportation infrastructure, and in particular:
    - our ability to acquire capacity in pipelines that deliver oil, NGLs and natural gas to commercial markets or alternatively contract for the delivery of our products by rail;
    - deliverability uncertainties related to the distance of our production from existing pipelines, railway lines, and processing and storage facilities; and
    - operational problems affecting the pipelines, railway lines and processing and storage facilities on which we rely;
- increased growth of shale oil and natural gas production in the U.S.;
- production and storage levels of oil, NGLs and natural gas;
- existing and threatened political instability and hostilities in commodity producing regions such as the Middle East, Northern Africa, Russia and elsewhere;
- sanctions imposed on certain oil producing nations (such as Russia) by other countries;
- foreign supply of, and demand for, oil, NGLs and natural gas, including liquefied natural gas;
- weather conditions;
- the overall economic and political environment in Canada, the U.S., Europe, China, Russia, emerging markets and globally;
- the overall level of energy demand;
- government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business;
- currency exchange rates, interest rates and inflation rates;

- the effect of worldwide environmental and/or energy conservation measures;
- the price and availability of alternative energy supplies; and
- the advent of new technologies.

We make price assumptions that are used for planning purposes, and a significant portion of our cash outflows, including transportation commitments, are largely fixed in nature. Accordingly, if commodity prices are below the expectations on which these commitments were based, our financial results are likely to be adversely and disproportionately affected because these cash outflows are not variable in the short term and cannot be quickly reduced to respond to unanticipated decreases in commodity prices. Our risk management arrangements will not fully mitigate the effects of price volatility.

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 our reserves. We might also elect not to produce from certain wells at lower prices. 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.

All these factors could result in a material decrease in our expected net production revenue and a reduction in our oil and natural gas production, acquisition, development and exploration activities. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the carrying value of our reserves, borrowing capacity, revenues, profitability and cash flows provided by operating activities and may have a material adverse effect on our business, financial condition, results of operations and prospects, and as a result, the market price of our Common Shares.

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, 2022, see the Corporation's audited financial statements for the year ended December 31, 2022, which have been filed on SEDAR and may be viewed under the Corporation's profile at www.sedar.com.

The Corporation's natural gas production from the McCully field 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*".

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. Adverse 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.

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

We utilize multi-well pad drilling where practicable. Problems affecting a single well could adversely affect production from all of the wells on the pad. As a result, multi-well pad drilling can cause delays in the scheduled commencement of production, or interruption in ongoing production. These delays or interruptions may cause volatility in our operating results.

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 COVID-19 pandemic, the implementation of computerized trading and the decrease of discretionary commodity trading. In addition, the volatility, trading volume and market price of the securities of oil and natural gas companies 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, debt levels 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 and may also result in the loss of key employees, the disruption of ongoing business, supplier, customer and employee relationships and deficiencies in internal controls or information technology controls. We continually assess the value and mix of our assets in light of our business plans and strategic objectives. In this regard, non-core assets may be periodically disposed of so we can focus our efforts and resources more efficiently. Depending on the market conditions for such non-core assets, certain of our non-core assets may realize less on disposition than their carrying value on our financial statements.

Acquisitions of oil and natural gas properties or companies will be based in part on engineering and economic assessments made by independent engineers. These assessments include a series of assumptions regarding such factors as recoverability and marketability of oil and natural gas, future prices of oil and natural gas and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond our control. All such assessments involve a measure of geological and engineering uncertainty that could result in lower production and reserves than anticipated. If actual reserves or production are less than we expect, our revenues and consequently the value of our Common Shares could be negatively affected.

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 factors 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 mandating the sale of electric vehicles, and the use of alternative fuels or uncompetitive fuel components, could affect the demand for our products. Many governments are providing tax advantages and other subsidies to support alternative energy sources or are mandating the use of specific fuels, technologies or electric vehicles. 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, demonstrations and vandalism 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.

Additional Factors Contributing to Adverse Economic Conditions

A reduction in the demand for energy, including crude oil, NGLs and natural gas, due to certain broad-based economic activities may have an adverse impact on the Corporation's financial condition, financial performance, and cash flows provided by operating activities.

The demand for energy, including crude oil, NGLs and natural gas, is generally linked to broad-based economic activities. If there was a slowdown in economic growth, an economic downturn or recession, or other adverse economic or political development in the U.S., Europe, Asia or elsewhere, there could be a significant adverse effect on global financial markets and commodity prices. In addition, hostilities in the Middle East, Ukraine, and Taiwan and the occurrence or threat of terrorist attacks in the U.S. or other countries could adversely affect the global economy. Global or national health concerns, including the outbreak of pandemic or contagious diseases, such as COVID-19, may adversely affect us by (i) reducing global economic activity thereby resulting in lower demand for crude oil, NGLs and natural gas, (ii) impairing our supply chain, for example, by limiting the manufacturing of materials or the supply of goods and services used in our operations and (iii) affecting the health of our workforce, rendering employees unable to work or travel. These and other factors disclosed elsewhere herein that affect the supply and demand for crude oil, NGLs and natural gas, and our business and industry, could ultimately have an adverse impact on our financial condition, financial performance and cash flows provided by operating activities.

Uncertainty resulting from the COVID-19 pandemic may 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, NGLs and natural gas. Since 2020, oil prices have recovered from their historic lows, but price support from future demand cannot be assured as countries continue to experience varying degrees of virus outbreak and newly emerging virus variants. 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 our operational results and financial condition. Low prices for oil, NGLs and natural gas would reduce our cash flows provided by operating activities, and impact our 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, any resurgence of COVID-19 may cause disruptions to production operations, reduced access to materials and services, increased employee absenteeism from illness, and temporary closures of our facilities.

The extent to which our operational and financial results are affected by COVID-19 will depend on various factors and consequences beyond our control, including but not limited to: the duration and scope of the pandemic; additional actions taken by business and government in response to any resurgence of the pandemic; and the speed and effectiveness of responses to combat any resurgence of 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. The lack of firm pipeline capacity, production limits and limits on availability of capacity in gathering and processing facilities, pipeline systems or railway lines continues to affect the oil and natural gas industry and limits the ability to transport produced oil and natural gas to market. In addition, the pro-rationing of capacity on interprovincial pipeline systems from time to time affects the ability of oil and natural gas companies to export oil and natural gas, and could result in our inability to realize the full economic potential of our production or in a reduction of the price we receive for our products. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the Corporation's production, operations and financial results.

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

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

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 the enhancement of 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, water 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 the Corporation's 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 have 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. Government authorities may issue orders to temporarily shutdown or curtail the injection depth of existing wells in the vicinity of seismic events.

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 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. To a lesser extent, we also face competition from companies that supply alternative sources of energy, such as wind and solar power. Other factors that could affect competition in the marketplace include additional discoveries of hydrocarbon reserves by our competitors, the cost of production, and political and economic factors and other factors outside of our control.

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, electric vehicle mandates, 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 other hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of hydrocarbons and encourage the use of renewable fuel alternatives (including electric vehicles), 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 flows provided by operating activities by decreasing the Corporation's profitability, increasing its costs, limiting its access to capital and decreasing the value of its assets.

Regulatory

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

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

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

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

Royalty Regimes

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

There can be no assurance that the governments in the jurisdictions in which the Corporation has assets will not adopt new royalty regimes, or modify the existing royalty regimes, which may have an impact on the economics of the

Corporation's projects. An increase in royalties would reduce the Corporation's earnings and could make future capital investments, or the Corporation's operations, less economic. See "*Industry Conditions – Royalties and Incentives*".

Environmental

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

All phases of the 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 suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and 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 Common 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. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*" for a summary of Canada's subsequent actions and pledges aimed at reducing Canada's GHG emissions and environmental impact. As discussed below, the Corporation faces both transition risks and physical risks associated with climate change and climate change policy and regulations.

Transition risks

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

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

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

Emissions, carbon and other regulations impacting climate and climate-related matters are constantly evolving. We are committed to reporting on our sustainability performance, and consider existing standards such as the Global Reporting Initiative Sustainability Reporting Standards and the Sustainability Accounting Standards Board Oil & Gas – Exploration & Production standard. In addition, the Canadian Securities Administrators have published for comment the proposed National Instrument 51-107 – *Disclosure of Climate Related Matters*, which is intended to introduce climate-related disclosure requirements for reporting issuers in Canada with limited exceptions. If we are not able to meet future sustainability reporting requirements of regulators or current and future expectations of investors, insurance providers, or other stakeholders, our 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. We do not conduct fundamental research regarding the scientific inquiry of climate change, but do stay abreast of scientific literature on the subject. 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, 2022, see the Corporation's audited financial statements for the year ended December 31, 2022, which have been filed on SEDAR and may be viewed under the Corporation's profile at 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 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, reduce operations or terminate operations on one or more properties. 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/or credit and/or increased capital raising and/or borrowing costs. Recent conditions in the oil and natural gas industry have at times negatively affected the ability of oil and natural gas companies to access additional equity and/or debt financing and/or increased the cost of such financing.

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 and/or credit 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 equity 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 the development or production on the Corporation's properties or force the Corporation to divest of certain assets that it would not otherwise sell.

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 increase 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 or 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 flows provided by operating activities, and profitability.

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

Credit Facility Arrangements

Default under Headwater's Credit Facility could result in the Corporation being required to repay amounts outstanding thereunder.

Headwater is required to comply with covenants under our Credit Facility, which include certain financial ratio tests, which, from time to time, either affect the availability, or price, of additional funding and in the event that we do not comply with these covenants, our access to capital could be restricted or repayment could be required. Events beyond our control may contribute to our failure to comply with such covenants. A failure to comply with covenants could result in default under our Credit Facility which could result in us being required to repay amounts owing thereunder.

The acceleration of our indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, our Credit Facility may impose operating and financial restrictions on us that could include restrictions on the payment of dividends, repurchase or making of other distributions with respect to our securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, the entering into of amalgamations, mergers, take-over bids or acquisitions, and the disposition of assets, among others.

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

Issuance of Debt

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

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

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 physical or financial agreements to receive fixed prices on its oil and natural gas production, which is intended to mitigate the effect of commodity price volatility and support the Corporation's capital budgeting and expenditure plans. 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 contracted 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 contractual arrangement;
- counterparties to the contractual 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.

On the other hand, failure to protect against a decline in commodity prices exposes the Corporation to reduced liquidity when prices decline. A sustained lower commodity price environment would result in lower realized prices for unprotected volumes and reduce the prices at which the Corporation would enter into derivative contracts on future volumes. This could make such transactions unattractive, and, as a result, some or all of the Corporation's production volumes forecasted for the current fiscal year and beyond may not be protected by derivative arrangements.

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, 2022, see the Corporation's audited financial statements for the year ended December 31, 2022, which have been filed on SEDAR and may be viewed under the Corporation's profile at 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 provided by operating activities.

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 provided by operating activities.

Title to and Right to Produce from Assets

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

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise. 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:

- commodity prices;
- historical production from properties;
- production rates and estimated production decline rates;
- estimated ultimate reserve recovery;
- effectiveness of waterflood:
- changes in technology;
- timing, amount and effectiveness of future capital expenditures;
- marketability of oil, NGLs 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, NGL 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 and probable reserves that may be developed and produced in the future is often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas are often estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

In accordance with applicable securities laws, the Corporation's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil, NGL 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, NGL 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 are not undertaken or, if undertaken, 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, the inability to obtain insurance coverage against one or more risks at acceptable premium rates or at all, 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 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, increased costs and/or cost overruns, and reduced access to (or an increase in the cost of) capital, credit and/or insurance coverage. 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, credit and/or insurance coverage, increasing the cost of capital, credit and/or insurance coverage and decreasing the price and liquidity of the Corporation's securities.

Changing Investor Sentiment

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

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

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. Shareholder dilution may also result from the issuance of Common Shares pursuant to the Corporation's equity incentive plans. For more information regarding Headwater's equity incentive plans, see our most recent Information Circular and Proxy Statement, financial statements and related management's discussion and analysis filed on SEDAR at www.sedar.com.

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

Historical cash dividends may not be reflective of future cash dividends; various factors beyond our control affect our financial condition which may result in cash dividends being reduced or suspended.

The amount of future cash dividends paid by us, if any, will be subject to the discretion of our Board and may vary depending on a variety of factors and conditions existing from time to time, including, among other things, fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends. Depending on these and various other factors, many of which will be beyond our control, our dividend policy from time to time and, as a result, future cash dividends could be reduced or suspended entirely.

The market value of our Common Shares may deteriorate if cash dividends are reduced or suspended. Furthermore, the future treatment of dividends for tax purposes will be subject to the nature and composition of dividends paid by us and potential legislative and regulatory changes. Dividends may be reduced during periods of lower cash flow, which result from lower commodity prices and any decision by us to finance capital expenditures using cash flows provided by operating activities.

To the extent that external sources of capital, including in exchange for the issuance of additional Common Shares, become limited or unavailable, our ability to make the necessary capital investments to maintain or expand petroleum and natural gas reserves and to invest in assets, as the case may be, will be impaired. To the extent that we are required to use cash flows provide by operating activities to finance capital expenditures or property acquisitions, the cash available for dividends may be reduced.

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

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

Breach of Confidentiality

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

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

Income Taxes

Taxation authorities may reassess the Corporation's tax returns.

The Corporation files all required income tax returns and believes that it is in 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, or other laws or government incentive programs relating to the oil and natural gas industry, such as the treatment of resource taxation, dividends, share repurchases or capital gains, may in the future be changed or interpreted in a manner that adversely affects the Corporation and/or Shareholders. 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 and/or the detriment of Shareholders.

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, counterparties to its derivative risk management contracts, 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 and from purchasers of assets from the Corporation for various liabilities, including well abandonment and reclamation obligations assumed by the purchasers. In the event such entities fail to meet their contractual obligations to us, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, from time to time there may be poor credit conditions in the industry generally and/or of one or more of our joint venture partners in particular, which may affect a joint venture partner's willingness to participate in our ongoing capital program, potentially delaying the program and the results of such program until we find a suitable alternative partner. The use of derivative risk management contracts involves the risk that the counterparties will be unable to meet the financial terms of such transactions. We are unable to predict changes in a counterparty's creditworthiness or ability to perform. Even if we accurately predict such changes, our ability to negate this risk may be limited depending upon market conditions and the contractual terms of the agreements. During periods of declining commodity prices, our derivative receivable positions may increase, which would increase our counterparty credit exposure. 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 of our directors and officers are engaged in, and will continue to engage in, other activities in the oil and natural gas industry and, as a result of these and other activities, our directors and officers may become subject to conflicts of interest. The ABCA provides that in the event that a director or officer of Headwater is a party to a material contract or material transaction or proposed material contract or proposed material transaction with us, or is a director or officer of or has a material interest in any person who is a party to a material contract or material transaction or proposed material contract or proposed material transaction with us, the director or officer must disclose the nature and extent of his or her interest and, if a director, must refrain from voting on any resolution to approve the contract or transaction unless otherwise provided under the ABCA. To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of the ABCA and the Corporation's Code of Business Conduct and Ethics. 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. In addition, the decline in market conditions in recent years has resulted in a significant number of skilled personnel exiting the oil and gas industry and fewer young people entering the industry. 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 Corporation. 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, consultants, securityholders and other stakeholders, regulators and other third parties.

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, credit card and banking details (and money), or approval of wire transfer requests, by disguising themselves 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. As a result, social media continues to grow in influence and access to social media platforms becomes increasingly prevalent, there are significant risks that the Corporation may not be able to properly regulate social media use and preserve adequate records of business activities conducted through the use of social media platforms.

Forward-Looking Information

Forward-looking statements may prove inaccurate.

Shareholders and prospective investors are cautioned not to place undue reliance on the Corporation's forward-looking statements. By their nature, forward-looking statements involve 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 statements or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Additional information on the risks, assumptions 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 transportation infrastructure, including 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;
- the effects of inclement and severe weather events, including fire, drought, flooding and extreme cold temperatures;
- availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;

- commodity price and 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.

If our cash flow and funds from external financing sources are not sufficient to cover our capital expenditure requirements, we may be required to reallocate available capital among our projects or modify our capital expenditure plans, which may result in delays to, or cancellation of, certain projects or deferral of certain capital expenditures. Any change to our capital expenditure plans could, in turn, have a material adverse effect on our growth objectives and our business, financial position, and results of operations. 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 may prevent, delay or make operations more difficult. Consequently, municipalities and provincial transportation departments may enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Road bans and other restrictions generally result in a reduction of drilling and exploratory activities and may also result in the shut-in of some of our production, if not otherwise tied-in. Certain of our oil and natural gas producing areas may from time to time 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 (swampy terrain). In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict our ability to access our properties and cause operational difficulties, including damage to machinery, or contribute to personnel injury because of dangerous working conditions.

Our operations may also be susceptible to the impacts of wildfires and flooding. In addition to the loss of revenue that would result from the loss of production if our operations are affected by wildfires and/or flooding, we would incur delays and expenses responding to such events, repairing damaged equipment, and resuming operations. Although our insurance policies may compensate us for part of our losses, they would not compensate us for all of our losses. In addition, wildfires and/or flooding consume both financial resources and management and employee time that would otherwise be directed towards the development of our business and the pursuit of our business strategy. We can offer no assurance that the severe wildfires and flooding that have at times affected the oil and gas industry in Western Canada will not occur again in the future with equal or greater severity.

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.

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

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 to operation sites; (iv) operating standards regarding conservation of produced substances and avoidance of waste, such as restricting flaring and venting; (v) minimizing environmental impacts, including by reducing emissions; (vi) storage, injection and disposal of substances associated with production operations; and (vii) the abandonment and reclamation of impacted sites. In order to conduct oil and natural gas operations and remain in good standing with the applicable federal or provincial regulatory scheme, producers must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance in this regard can be costly and a breach of the same may result in fines or other sanctions.

The discussion below outlines some of the principal aspects of the legislation, regulations, agreements, orders, directives and a summary of other pertinent conditions that impact the oil and gas industry in 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 2022, oil prices rose to the highest levels since 2014 due to tight supply and a resurgence in demand. OPEC+ forecasts robust growth in world oil demand in 2023, spurred by the relaxation of China's zero-COVID policy. OPEC+ predicts global oil demand to rise by 2.25 million barrels per day in 2023, despite newly emerging COVID-19 variants, interest rate increases in major economies and other uncertainties with respect to the world economy.

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

Natural Gas

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

Natural Gas Liquids

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

Transportation Constraints and Market Access

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

Oil Pipelines

Under Canadian constitutional law, the development and operation of interprovincial and international pipelines fall within the federal government's jurisdiction and, under the CERA, new interprovincial and international pipelines require a federal regulatory review and approval of the cabinet of the Canadian federal government ("**Cabinet**") 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.

Specific Pipeline Updates

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of political opposition in British Columbia, the federal government acquired the Trans Mountain Pipeline in August 2018. Following the resolution of a number of legal challenges and a second regulatory hearing, construction on the Trans Mountain Pipeline expansion commenced in late 2019. Earlier estimated at $12.6 billion, the project budget has risen to $21.4 billion as of February 2022. The pipeline is expected to be in service in the third quarter of 2023, an extension from Trans Mountain's initial December 2022 estimate. The budget increase and in-service date delay have been attributed to, among other things, the ongoing effects of the COVID-19 pandemic and the widespread flooding in British Columbia in late 2021.

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

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

Marine Tankers

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

Natural Gas and Liquefied Natural Gas ("LNG")

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

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

Specific Pipeline and Proposed LNG Export Terminal Updates

While a number of LNG export plants have been proposed in Canada, regulatory and legal uncertainty, social and political opposition and changing market conditions have resulted in the cancellation or delay of many of these projects. Nonetheless, in October 2018, the joint venture partners of the LNG Canada LNG export terminal announced a positive final investment decision. Once complete, the project will allow producers in Northeastern British Columbia to transport natural gas to the LNG Canada liquefaction facility and export terminal in Kitimat, British Columbia via the Coastal GasLink pipeline (the "**CGL Pipeline**"). With more Alberta and Northeastern British Columbia gas egressing through the CGL Pipeline, the NGTL System is expected to have more capacity, which may result in a closer link between AECO and NYMEX gas prices. Phase 1 of the LNG Canada project reached 70% completion in October 2022, with a completion target of 2025.

In May 2020, TC Energy Corporation sold a 65% equity interest in the CGL Pipeline to investment companies KKR & Co Inc. and Alberta Investment Management Corporation while remaining the pipeline operator. Despite its regulatory approval, the CGL Pipeline has faced legal and social opposition. For example, protests involving the Hereditary Chiefs of the Wet'suwet'en First Nation and their supporters have delayed construction activities on the CGL Pipeline, although construction is proceeding. As of November 2022, construction of the CGL Pipeline was approximately 80% complete.

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

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

International Trade Agreements

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

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

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

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

Land Tenure

Mineral Rights

With the exception of Manitoba, each provincial government in Western Canada owns most of the mineral rights to the oil and natural gas located within their respective provincial borders. 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.

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

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

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

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

Surface Rights

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

Royalties and Incentives

General

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

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

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

Alberta

Crown Royalties

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

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

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

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

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

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

Freehold Royalties and Taxes

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

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

Incentives

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage crude oil and natural gas development and new drilling. In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources, including coalbed methane wells, shale gas wells and horizontal crude oil and natural gas wells.

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 ("**CO2e**")), may impose further requirements on operators and other companies in the oil and gas industry.

Federal

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

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

The IAA relies on a designated project list as a trigger for a federal assessment. Designated projects that may have effects on matters within federal jurisdiction will generally require an impact assessment administered by the 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.

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

Alberta

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

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

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

The AER monitors seismic activity across Alberta to assess the risks associated with, and instances of, earthquakes induced by hydraulic fracturing. Hydraulic fracturing involves the injection of water, sand or other proppants and additives under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate oil and natural gas production. In recent years, hydraulic fracturing has been linked to increased seismicity in certain 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 or Brazeau, however, the AER may extend seismic protocols to other areas of the Province if necessary, which may adversely affect our operations.

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

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

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

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

Alongside changes to Directive 067, the AER introduced *Directive 088: Licensee Life-Cycle Management* ("**Directive 088**") in December 2021 under the AB LM Framework. Directive 088 replaces, to an extent, the AB LLR Program with the AB LCA. Whereas the AB LLR Program previously assessed a licensee based on a liability rating determined by the ratio of a licensee's deemed asset value relative to the deemed liability value of its oil and gas wells and facilities, the AB LCA now considers a wider variety of factors and is intended to be a more comprehensive assessment of corporate health. Such factors are wide reaching and include: (i) a licensee's financial health; (ii) its established total magnitude of liabilities; (iii) the remaining lifespan of its mineral resources and infrastructure; (iv) the management of its operations; (v) the rate of closure activities and spending, and pace of inactive liability growth; and (vi) its compliance with administrative and regulatory requirements. These various factors 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 AB LLR Program is still in effect for other liability management programs such as the AB OWL Program and the AB LF Program, and will remain in effect until a broadened scope of Directive 088 is phased in over time.

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

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

To address abandonment and reclamation liabilities in Alberta, the AER also implements, from time to time, programs intended to encourage the decommissioning, remediation and reclamation of inactive or marginal oil and natural gas infrastructure. In 2018, for example, the AER announced a voluntary area-based closure ("**ABC**") program. The ABC program is designed to reduce the cost of abandonment and reclamation operations 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 performed on 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.

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

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

The Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change in 2016, setting out a plan to meet the federal government's 2030 emissions reduction targets. On June 21, 2018, the federal government enacted the Greenhouse Gas Pollution Pricing Act (the "**GGPPA**"), which came into force on January 1, 2019. This regime has two parts: an output-based pricing system ("**OBPS**") for large industry (enabled by the Output-Based Pricing System Regulations) and a fuel charge (enabled by the Fuel Charge Regulations), both of which impose a price on CO2e emissions. This system applies in provinces and territories that request it and in those that do not have their own equivalent emissions pricing systems in place that meet the federal standards and ensure that there is a uniform price on emissions across the country. Originally under the federal plans, the price was set to escalate by $10 per year until it reached a maximum price of $50/tonne of CO2e in 2022; however, on December 11, 2020, the federal government announced its intention to continue the annual price increases beyond 2022. Commencing in 2023, the benchmark price per tonne of CO2e will increase by $15 per year until it reaches $170/tonne of CO2e in 2030. Effective January 1, 2023, the minimum price permissible under the GGPPA rose to $65/tonne of CO2e. While several provinces challenged the constitutionality of the GGPPA following its enactment, the Supreme Court of Canada confirmed its constitutional validity in a judgment released on March 25, 2021.

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

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

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

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

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

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

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

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

Alberta

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

In June 2019, the fuel charge element of the federal backstop program took effect in Alberta. On January 1, 2023, the carbon tax payable in Alberta increased from $50 to $60 per tonne of CO_2e, and will continue to increase at a rate of $15 per year until it reaches $170 per tonne in 2030. In December 2019, the federal government approved Alberta's *Technology Innovation and Emissions Reduction* ("**TIER**") regulation, which applies to large emitters. The TIER regulation came into effect on January 1, 2020 (as amended on January 1, 2023) and replaced the previous *Carbon Competitiveness Incentives Regulation*. The TIER regulation meets the federal benchmark stringency requirements for emissions sources covered in the regulation, but the federal backstop continues to apply to emissions sources not covered by the regulation.

The TIER regulation applies to emitters that emit more than 100,000 tonnes of CO_2e per year in 2016 or any subsequent year. The initial target for most TIER-regulated facilities is to reduce emissions intensity by 10% as measured against that facility's individual benchmark, with a further 2% reduction in each subsequent year. The facility-specific benchmark does not apply to all facilities, such as those in the electricity sector, which are compared against the good-as-best-gas standard. Similarly, for facilities that have already made substantial headway in reducing their emissions, a different "high-performance" benchmark is available. Under the TIER regulation, certain facilities in high-emitting or trade exposed sectors can opt-in to the program in specified circumstances if they do not meet the 100,000 tonne threshold. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports and facilities that are unable to achieve their targets may either purchase credits from other facilities, purchase carbon offsets, or pay a levy to the Government of Alberta.

The Government of Alberta aims to lower annual methane emissions by 45% by 2025. The Government of Alberta enacted the *Methane Emission Reduction Regulation* on January 1, 2020, and in November 2020, the Government of Canada and the Government of Alberta announced an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in Alberta.

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 CO2e per year will be subject to a mandatory emissions reduction requirements and charges for non-compliance. Facilities that emit more than 10,000 tonnes of CO2e but less than 50,000 CO2e may opt-in to the program. Facilities that fail to meet their targets may purchase credits to offset their surplus emissions and facilities that exceed their reductions targets can earn performance credits that they can then sell to other facilities. 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 DRIPA became law in British Columbia. The DRIPA aims to align British Columbia's laws with UNDRIP. In June 2021, the UNDRIP Act came into force in Canada. Similar to British Columbia's DRIPA, the UNDRIP Act requires the Government of Canada to take all measures necessary to ensure the laws of Canada are consistent with the principles of UNDRIP and to implement an action plan to address UNDRIP's objectives. On June 21, 2022, the Minister of Justice and Attorney General issued the First Annual Progress Report on the implementation of the UNDRIP Act (the "**Progress Report**"). The Progress Report provides that, as of June 2022, the federal government has sought to implement the UNDRIP Act by, among other things, creating a Secretariat within the Department of Justice to support Indigenous participation in the implementation of UNDRIP, consulting with Indigenous peoples to identify their priorities, drafting an action plan to align federal laws with UNDRIP, and implementing efforts to educate federal departments on UNDRIP's principles.

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

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

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

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

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

LEGAL PROCEEDINGS

Headwater is not a party to any legal proceeding nor was it a party to any legal proceeding during the 2022 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, 2022 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 entered into with Headwater 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.

Name and Place of Residence	Independent	Financially Literate	Relevant Education and Experience
Chandra Henry Alberta, Canada	Yes	Yes	Ms. Henry is currently Chief Financial Officer and Chief Compliance Officer of Longbow Capital Inc. and is a director of Whitecap Resources Inc. Ms. Henry was formerly a director of Bonavista Energy Corporation and 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) Credential Holder.
Kevin Olson Alberta, Canada	Yes	Yes	Mr. Olson has 30 years of industry experience and currently serves on the board of directors of Lycos Energy Inc. Mr. Olson is a former board member of Baytex, Raging River, Wild Stream, Wild River and Prairie Schooner Petroleum Ltd. Mr. Olson has managed four early stage energy funds and served as a director of a variety of exploration and production companies and petroleum services companies. Formerly, Mr. Olson was Vice-President, Corporate Finance at FirstEnergy Capital Corp. and Vice-President, Corporate Development for Northrock Resources Ltd. Mr. Olson holds a Bachelor of Commerce degree (Distinction) majoring in finance and accounting from the University of Calgary.

Name and Place of Residence	Independent	Financially Literate	Relevant Education and Experience
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 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, 2022	Fees Paid for Period Ended December 31, 2021
Audit Fees(1)		
KPMG LLP	$196,613	$220,752
PricewaterhouseCoopers LLP	$nil	$nil
Audit-Related Fees(2)		
KPMG LLP(5)	$nil	$84,263
PricewaterhouseCoopers LLP(5)	$nil	$48,311
Tax Fees(3)		
KPMG LLP	$nil	$4,458
PricewaterhouseCoopers LLP	$nil	$nil
All Other Fees(4)		
KPMG LLP	$nil	$nil
PricewaterhouseCoopers LLP	$nil	$nil
Total		
KPMG LLP	**$196,613**	**$309,473**
PricewaterhouseCoopers LLP	**$nil**	**$48,311**

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 $nil/PricewaterhouseCoopers LLP $nil 2022 / KPMG LLP $4,458/PricewaterhouseCoopers LLP $nil 2021), tax planning (KPMG LLP $nil/PricewaterhouseCoopers LLP $nil 2022 / KPMG LLP $nil/PricewaterhouseCoopers LLP $nil 2021) and tax advice (KPMG LLP $nil/PricewaterhouseCoopers LLP $nil 2022 / KPMG LLP $nil/PricewaterhouseCoopers LLP $nil 2021). 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. 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 and Safety 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 and Safety 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 and Safety 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 9th day of March, 2023.

(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 EVALUATOR

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

1. We have evaluated the Company's reserves data as at December 31, 2022. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2022, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook, as amended from time to time (the "**COGE Handbook**") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2022, and identifies the respective portions thereof that we have 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, 2022	Canada	nil	829,802	nil	829,802

6. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

7. We have no responsibility to update our report referred to in paragraph 5 for events and circumstances occurring after the effective date of our report.

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 24, 2023.

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 filling their responsibilities at such compensation as established by the Committee and at the expense of the Corporation without any further approval of the Board.

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

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