ALTURA ENERGY INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2020

April 28, 2021

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CERTAIN DEFINITIONS

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

"**Altura**" or the "**Corporation**" means Altura Energy Inc.;

"**ABCA**" means the *Business Corporations Act* (Alberta);

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

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

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

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

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society), as amended from time to time;

"**Common Share**" or "**Common Shares**" means, respectively, one or more common shares in the capital of the Corporation;

"**development costs**" means costs incurred to develop reserves and to provide facilities for extracting, treating, gathering and storing the crude oil and natural gas from 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, 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 cost of 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 hydrocarbon recovery systems;

"**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 crude oil and natural gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property 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;

b) Costs of carrying and retaining unproved properties, such as land rentals, taxes (other than income and capital taxes) on properties, legal costs for title defense, and the maintenance of land and lease records;

c) Costs for dry hole contributions and bottom hole contributions; and

d) Costs of drilling and equipping exploratory wells.

"**gross**" means:

a) In relation to the Corporation's interest in production and reserves, its "Corporation gross reserves", which are the Corporation's working interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Corporation;

b) In relation to wells, the total number of wells in which the Corporation has an interest; and

c) In relation to properties, the total area of properties in which the Corporation has an interest;

"**IFRS**" means International Financial Reporting Standards;

"**LLR**" means Licensee Liability Rating;

"**McDaniel**" means McDaniel & Associates Consultants Ltd.;

"**McDaniel Report**" means the report prepared by McDaniel, in accordance with NI 51-101, dated April 14, 2021 and effective December 31, 2020;

"**net**" means:

a) In relation to the Corporation's interest in production and reserves, the Corporation's working interest (operating and non-operating) share after deduction of royalty obligations, plus the Corporation's royalty interest in production or reserves;

b) In relation to wells, the number of wells obtained by aggregating the Corporation's working interest in each of its gross wells; and

c) In relation to the Corporation's interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation;

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

“**Options**” means options to purchase Common Shares granted under the Corporation’s stock option plan;

"**Preferred Share**" or "**Preferred Shares**" means, respectively, one or more preferred shares in the capital of the Corporation;

"**TSXV**" means the TSX Venture Exchange;

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

Words importing the singular number only include the plural, and vice versa, and words importing any gender include all genders. The information set out in this Annual Information Form is stated as at December 31, 2020 unless otherwise indicated and except that information in documents incorporated by reference herein is given as of the dates noted therein.

SELECTED ABBREVIATIONS

In this AIF, the abbreviations set forth below have the following meanings:

Oil and Natural Gas Liquids		**Natural Gas**	
Bbl	Barrel of oil or NGLs	Mcf	thousands of cubic feet
Bbls	barrels of oil or NGLs	Mcfe	thousands of cubic feet equivalent
Bbls/d	barrels per day	MMcf	millions of cubic feet
Mbbl	thousands of barrels of oil or NGLs	Mcf/d	thousands of cubic feet per day
NGLs	natural gas liquids	Mcfe/d	thousands of cubic feet equivalent per day

API	American Petroleum Institute
° API	is an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specific gravity of 31.1º API or higher is generally referred to as light crude oil
Boe	barrel of oil equivalent of natural gas and crude oil on the basis of one Bbl for six Mcf of natural gas
Boe/d	barrel of oil equivalent per day
MBoe	1,000 barrels of oil equivalent
M$	thousands of dollars
OPEC	Organization of Petroleum Exporting Countries
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

CONVERSION

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

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	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609

Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471

CURRENCY OF INFORMATION

In this AIF, references to "dollars" and "$" are to the currency of Canada, unless otherwise indicated.

OIL AND GAS ADVISORIES

Caution Respecting Boe

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

NON-GAAP MEASURES

Within this AIF, references are made to terms commonly used in the oil and natural gas industry. The term "Netback" in this AIF is not a recognized measure under generally accepted accounting principles in Canada. Altura uses "Netback" as a key performance indicator in operational and capital allocation decisions. It is determined by deducting transportation expenses, royalties and operating expenses from revenues. Readers are cautioned, however, that this measure should not be construed as an alternative to net earnings determined in accordance with generally accepted accounting principles in Canada as an indication of Altura's performance.

NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain information set forth in this Annual Information Form, including certain documents incorporated by reference into this Annual Information Form, contain forward-looking information (within the meaning of applicable Canadian securities legislation). Such statements or information are generally identifiable by words such as "anticipate", "believe", "intend", "plan", "expect", "estimate", "budget", "outlook", "forecast", "will" or other similar words and include statements relating to or associated with individual wells, facilities, regions or projects. Any statements regarding the following are forward-looking statements:

- uncertainty about the COVID-19 pandemic and the impact it will have on Altura's operations, the demand for Altura's products, and economic activity in general;
- the performance characteristics of the Corporation's oil and natural gas properties;
- future crude oil, NGLs and natural gas prices;
- future production levels and production levels by commodity;
- future drilling, completion and tie-in of wells;
- development plans for proved and probable undeveloped reserves;
- anticipated land expiries;
- future facility access, acquisition or construction;
- future availability of financing, future sources of funding for capital programs and future availability of such sources;
- availability of credit facilities;

- future asset acquisitions or dispositions;
- intentions with respect to investments;
- future decommissioning costs and the related discount rates and inflation factors used to determine such estimates;
- development plans;
- 2021 capital budget;
- future development potential on the Corporation's lands;
- expectations with respect to future growth and opportunities;
- treatment under governmental regulatory regimes and tax and royalty laws;
- the anticipated impact of the factors discussed under the heading "*Industry Conditions*" on the Corporation;
- dates or time periods by which wells will be drilled, completed and tied in, facility and pipeline construction completed and geographical areas developed; and
- changes to any of the foregoing.

With respect to forward-looking statements contained in this Annual Information Form, including certain documents incorporated by reference into this Annual Information Form, the Corporation has made assumptions regarding:

- the continued performance of Altura's crude oil and natural gas properties in a manner consistent with its past experiences;
- that Altura will continue to conduct its operations in a manner consistent with past operations;
- the return of industry conditions to pre-COVID-19 pandemic levels;
- oil and natural gas production rates;
- the size of the oil and natural gas reserves;
- projections of market prices and costs;
- supply and demand for crude oil and natural gas;
- the success of the Corporation's operations and exploration and development activities;
- prevailing weather conditions, commodity prices and exchange rates;
- the availability of labour, services and drilling equipment;
- the availability of capital to fund planned expenditures;
- timing and amount of capital expenditures;
- future abandonment and reclamation costs;
- general economic and financial market conditions;
- tax horizons;
- the success, nature and timing of enhanced recovery activities;
- the ability of the Corporation to secure necessary personnel, equipment and services;
- government regulation in the areas of taxation, royalty rates and environmental protection;
- the success of exploration and development activities; and

- access to market for the Corporation's production.

The forward-looking statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include:

- the COVID-19 pandemic and related disruptions in crude oil and natural gas markets, including the duration and impacts thereof;
- changes in commodity prices including, without limitation, as a result of COVID-19;
- changes in commodity prices including, without limitation, as a result of the COVID-19 pandemic and related disruptions in crude oil and natural gas markets;
- industry conditions, including commodity prices;
- pipeline and third-party facility capacity constraints and access to sales markets;
- volatility of commodity prices;
- currency fluctuations;
- imprecision of reserve estimates and related costs including royalties, production costs and future development costs;
- environmental risks;
- stock market volatility;
- ability to access sufficient capital from internal and external sources and the ability of the Corporation to realize value from acquired assets and companies;
- credit facility risks;
- failure to realize anticipated benefits of acquisitions and dispositions;
- risks inherent in oil and natural gas operations;
- inability to secure labour, services or equipment on a timely basis or on favourable terms;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- unfavourable weather conditions;
- incorrect assessments of the value of acquisitions and exploration and development programs;
- success of drilling programs;
- geological, technical, drilling, completion and processing problems;
- results of enhanced recovery responses;
- changes in legislation, including changes in tax laws and incentive programs relating to the oil and gas industry; and
- the other factors discussed under "Risk Factors".

All of these factors should be considered in the context of current economic conditions, in particular, volatility in commodity prices, recent low prices for crude oil and natural gas over the last several years, the attitude of lenders and investors towards crude oil and natural gas assets, the condition of financial markets generally, as well as the stability of joint venture and other business partners, all of which are outside the control of the Corporation.

Ultimate recovery of reserves is based on forecasts of future results, estimates of amounts not yet determinable and assumptions of management of the Corporation.

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

Readers are advised that the assumptions used in the preparation of forward-looking 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. The Corporation disclaims any intention or obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required under securities law.

References to forward-looking information are made elsewhere in this Annual Information Form. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

THE CORPORATION

The Corporation was incorporated under the ABCA on June 8, 2007 under the name of "Northern Spirit Developments Inc." On November 2, 2007, the Corporation filed articles of amendment to change its name to "Northern Spirit Resources Inc." On January 1, 2012, the Corporation filed articles of amalgamation to amalgamate with Northern Spirit Operating Inc. and 1250900 Alberta Ltd. On October 16, 2015, the Corporation filed articles of amendment to change its name to "Altura Energy Inc."

The Corporation is a reporting issuer (or the equivalent thereof) in Alberta, British Columbia and Ontario. The Common Shares are listed and posted for trading on the TSXV under the symbol "ATU". Prior to October 19, 2015, the Common Shares traded on the TSXV under the symbol "NS".

The Corporation has one wholly owned subsidiary, 1880675 Alberta Ltd. 1880675 Alberta Ltd. is a corporation existing under the ABCA.

The Corporation's registered office is located at 1100, 225 – 6th Avenue S.W., Brookfield Place, Calgary, Alberta T2P 1N2, and its head and principal office is located at 2500, 605 – 5th Avenue S.W., Calgary, Alberta, T2P 3H5.

GENERAL DEVELOPMENT OF THE BUSINESS

From January 1, 2018 to December 31, 2020 the Corporation has grown its business by acquiring producing assets and land, either freehold or Crown, and drilling, completing and equipping wells on the assets owned by the Corporation, primarily in central Alberta. Set out below is a review of the Corporation's activities during such three-year period.

2018

Overview of Capital Expenditure Program

During the year ended December 31, 2018, the Corporation executed a $9.8 million capital program, including $3.6 million related to property acquisitions and net of divestitures totaling $27.3 million (including transaction costs). Drilling and completion projects included nine wells at Leduc-Woodbend, and one well in Saskatchewan. The Corporation invested in key infrastructure at Leduc-Woodbend including the construction of a multi-well battery and a natural gas gathering pipeline that connected Altura's production to a third party gas plant. Average production for the year was 1,172 Boe/d.

General Business Developments

On May 31, 2018, Altura closed the disposition of the Corporation's crude oil and natural gas assets (the "**Provost Disposition**"), to an unrelated third party, in east central Alberta and Saskatchewan, which included the Eyehill, Eyehill South, Macklin, Wildmere, Killam and Provost Minor areas. Consideration, net of customary post-closing adjustments and transaction costs totaled $27.3 million. The Provost Disposition strategically transformed the Corporation to a geographically and geologically focused Upper Mannville producer at Leduc-Woodbend, located 30 km south of Edmonton, Alberta.

In conjunction with the Provost Disposition, the revolving operating demand loan (the "**Operating Loan**") was decreased from $10.0 million to $3.0 million on May 31, 2018.

On July 31, 2018, the Corporation closed an acquisition of 2.6 net sections of highly prospective lands in the Upper Mannville oil pool at Leduc-Woodbend and a 40% working interest in the Glauconitic D Unit No. 1 pool in the Leduc-Woodbend area of Alberta from a third-party for cash consideration of $2.6 million, net of customary post-closing adjustments, adding net production of approximately 80 Boe per day (90% crude oil and NGLs) of low decline, Glauconitic light crude oil (33° API) production.

On December 13, 2018, the Operating Loan was increased from $3.0 million to $6.0 million.

On December 21, 2018, the Corporation closed a second agreement to purchase 0.4 net sections of highly prospective lands in the Upper Mannville oil pool at Leduc-Woodbend and a 20% working interest in the Glauconitic D Unit No. 1 pool from a second third-party for cash consideration of $1.0 million, net of customary post-closing adjustments, adding net production of approximately 40 Boe per day (90% crude oil and NGLs) of low decline, Glauconitic light crude oil (33° API) production.

2019

Overview of Capital Expenditure Program

During the year ended December 31, 2019, the Corporation executed a $9.4 million capital program, net of divestitures totaling $3.5 million. Altura drilled three and completed two wells at Leduc-Woodbend and drilled a vertical exploratory stratigraphic well in a new area called Entice, located south of Strathmore, Alberta. Additionally, the Corporation changed its artificial lift system on 11 wells totaling $0.8 million of workover expenditures and $1.2 million related to equipping expenditures. Average production for the year was 1,742 Boe/d.

General Business Developments

On April 29, 2019, the Credit Facility was increased from $6.0 million to $10.0 million. The interest rate on the Credit Facility was increased to the lender's prime rate plus 1.75% from its prime rate plus 1.50%, with a parallel increase in the fee for Letters of Credit issued under the Credit Facility to 2.25% (from 2.00%). Furthermore, the Credit Facility was amended to include additional covenants to be observed by the Corporation, including:

- a hedging covenant that Altura shall, from May 1, 2019 onwards, at all times maintain hedging agreements covering no less than 300 bbl/d crude oil (Western Canadian Select) for no less than the succeeding nine-month period, on a rolling basis; and
- the Corporation will maintain an Licensee Liability Rating in Alberta, Saskatchewan and British Columbia, in each case, of no less than 2.0.

On December 4, 2019, Altura entered into a definitive agreement with an unrelated third party ("**PrivateCo**") for the sale of a 12.5% working interest in the Corporation's production, wells, lands and facilities for cash of $7.0 million through two transactions (the "**Original Disposition Agreement**"). The agreement provided for a third transaction if it was mutually agreed that drilling a second well in the Entice area was warranted, whereby Altura would divest an additional 4.0% of corporate assets for $3.0 million. If all three transactions closed, Altura would have sold a total working interest of 16.5% of corporate assets, including asset retirement obligations ("**ARO**"), for total consideration of $10.0 million.

The Original Disposition Agreement committed Altura to the following:

1. Drill, complete and equip or abandon a horizontal well in the Entice area of Alberta by March 31, 2020 (the "**First Commitment Well**").
2. Spud a second horizontal well by December 31, 2020 (the "**Second Commitment Well**"). On or before October 30, 2020, Altura and PrivateCo would meet and review the production information and other data from the first Entice well. If it was mutually agreed that the drilling of a second well at Entice was warranted, Altura would select a location for the drilling of a horizontal well in the Entice area. If not mutually agreed that the drilling of a second well at Entice was warranted, Altura would select a location for the drilling of a horizontal well in the Leduc-Woodbend area. If the Second Commitment Well was drilled in the Entice area, PrivateCo would pay 7.0% of well costs and earn a 12.5% working interest in the well. If the Second Commitment Well was drilled in the Leduc-Woodbend area, PrivateCo would pay 12.5% of well costs and earn a 12.5% working interest in the well.
3. Within 10 business days of delivering the second well location notice to PrivateCo, Altura and PrivateCo would enter into a purchase and sale agreement for the second transaction whereby Altura would divest of an additional 5.5% working interest in the Corporation's production, wells, lands and facilities as at that date for cash of $3.5 million (the "**Second Transaction**"). Proceeds would be used to fund the Second Commitment Well.
4. In the event the Second Commitment Well was drilled at Entice and both parties agreed to drill a third well at Entice, the agreement provided for a third transaction whereby Altura would divest of an additional 4.0% working interest in the Corporation's production, wells, lands and facilities as at that date for cash of $3.0 million. Proceeds would primarily be used to drill a third horizontal well at Entice on or before December 31, 2021. PrivateCo would pay 12.5% of well costs and earn a 16.5% working interest in the well.

The first transaction closed on December 4, 2019, whereby Altura divested a 7.0% working interest for cash of $3.5 million.

In conjunction with the 7% working interest disposition on December 4, 2019, the Operating Loan was decreased from $10.0 million to $9.0 million.

2020

Overview of Capital Expenditure Program

During the year ended December 31, 2020, the Corporation executed a $6.1 million capital program, net of divestitures totaling $1.7 million. In March 2020, Altura halted all discretionary capital expenditures in response to the impacts of COVID-19 on the global economy. Prior to the COVID-19 pandemic, Altura completed a Leduc-Woodbend horizontal oil well (93% working interest) that was drilled in the third quarter of 2019 and drilled a Leduc-Woodbend horizontal oil well (93% working interest) that was completed in February 2021. At Entice, Altura incurred $4.0 million to drill, complete, and equip the First Commitment Well targeting the Pekisko Formation. Average production for 2020 was 880 Boe/d.

General Business Developments

On March 19, 2020, Altura announced that it eliminated all discretionary capital spending for the remainder of the 2020 due to the COVID-19 pandemic and the actions of Saudi Arabia and Russia in the global oil market which resulted in an unprecedent decline in crude oil prices.

On April 7, 2020, the Corporation announced it voluntarily curtailed production volumes in April 2020 to its hedged oil production of 300 barrels of crude oil per day, which was approximately 550 boe per day (including NGLs and natural gas) in response to the COVID-19 pandemic and related disruptions in crude oil and natural gas markets.

On April 7, 2020, the Operating Loan was capped at $7.5 million down from $9.0 million.

On May 28, 2020, the Corporation announced that it unwound its May 2020 hedging contracts, realizing a gain of $356,000, and shut in all corporate production for the month of May 2020 due to the severe decrease in crude oil prices caused by the COVID-19 pandemic.

On June 30, 2020, Altura announced it had amended the Original Disposition Agreement (the "**First Amending Agreement**") dated June 26, 2020 with PrivateCo, which divided the Second Transaction into four separate dispositions of a 1.375% working interest for $875,000 each. The four disposition stages were agreed to close on June 30, 2020, September 30, 2020, January 31, 2021 and June 30, 2021.

Given the economic environment on June 26, 2020 caused by the COVID-19 pandemic, drilling risk profile and capital efficiency in Leduc-Woodbend and Entice, the parties agreed the Second Commitment Well would be drilled at Leduc-Woodbend at a time when commodity prices supported well economics. Estimated total gross drill, complete and equipping costs of the well were $2.3 million. Given that the parties agreed for the Second Commitment Well to be drilled in the Leduc-Woodbend area, PrivateCo would pay 12.5% of the well costs and earn a 12.5% working interest in the Second Commitment Well. The optional third funding transaction contemplated by the Original Disposition Agreement was not executed by PrivateCo.

It was not mutually agreed that the drilling of the Second Commitment Well at Entice was warranted so the third transaction was terminated within the First Amending Agreement.

Altura closed stage one of the First Amending Agreement on June 30, 2020 divesting of a 1.375% working interest in the Corporation's production, wells, lands and facilities for cash of $871,000.

On July 30, 2020, the Operating Loan was reduced to $6.0 million from $7.5 million.

On August 28, 2020, Altura completed the redetermination of its Operating Loan and the borrowing base was confirmed at $6.0 million. Additionally, Altura secured a $3.0 million term loan from its lender through the Business Credit Availability Program ("**BCAP**") from the Export Development Bank of Canada ("**EDC**") (the "**Term Loan**"). The Operating Loan and the Term Loan (collectively the "**Credit Facilities**") provide Altura with $9.0 million of total Credit Facilities.

On September 30, 2020, Altura closed stage two of the First Amending Agreement divesting of a 1.375% working interest in the Corporation's production, wells, lands and facilities for cash of $875,000.

Recent Developments

On January 29, 2021, the Board of Directors approved a capital budget of $6.0 million for 2021, funded with forecasted cash flow from operating activities, available Credit Facilities, and the 2021 asset dispositions. The budget includes drilling two (1.8 net) Rex wells and completing three (2.7 net) Rex wells at Leduc-Woodbend. The 2021 capital expenditure budget targets an annual average production rate of 1,100 to 1,150 boe per day compared to 880 boe per day in 2020, representing more than 25% estimated growth on an absolute and per share basis.

On January 29, 2021, Altura announced it amended the timing of stages three and four of the Second Transaction in the First Amending Agreement (the "**Second Amending Agreement**") with PrivateCo, which divided stage three into two dispositions. Altura closed stage 3a of the Second Amending Agreement on January 29, 2021 divesting of a 0.6875% working interest in the Corporation's production, wells, lands and facilities for cash of $437,500 and closed stage 3b on April 27,2021 divesting of a 0.6875% working interest for $437,500. The remaining stages as at December 31, 2020 pursuant to the Second Amending Agreement are as follows:

Stage	Closing Date	Disposition Interest	Cash Proceeds
Stage 3a	January 29, 2021	0.6875%	$437,500
Stage 3b	April 27, 2021	0.6875%	$437,500
Stage 4	June 30, 2021	1.375%	$875,000
Total		2.75%	$1,750,000

Significant Acquisitions

The Corporation did not complete any significant acquisitions during its most recently completed financial year for which disclosure is required under Part 8 of National Instrument 51-102 – *Continuous Disclosure Obligations*.

DESCRIPTION OF THE BUSINESS

Corporate Strategy

Altura is a growth orientated, junior public oil and gas company with properties in central Alberta. The Corporation predominantly produces from the Rex reservoir in the Upper Mannville group and is focused on delivering per share growth and attractive shareholder returns through a combination of organic growth and strategic acquisitions.

While Altura believes that it has the skills and resources necessary to achieve its stated objectives, participation in the exploration for, and development of, crude oil and natural gas has several inherent risks. See "*Risk Factors*" in this AIF.

Employees

As at December 31, 2020, the Corporation employed seven full-time employees located at the head office. The Corporation also retained four consultants, two of which are located at the head office and two of which are located in the field.

In addition, the Corporation hires skilled contractors to perform drilling operations, well completions and other field service operations.

Specialized Skill and Knowledge

The Corporation employs individuals with various professional skills in the course of pursuing its business plan. In addition, the Corporation has access to various specialized consultants to assist in areas where it does not need full time employees. These professional skills include, but are not limited to, geology, geophysics, engineering, land, financial and business development. Drawing on significant experience in the crude oil and natural gas business, the Corporation believes its management team has a demonstrated track record of bringing together all of the key components to a successful exploration and production company: strong technical skills; expertise in planning and financial controls; ability to execute on business development opportunities; capital markets expertise; and an entrepreneurial spirit that allows the Corporation to effectively identify, evaluate and execute on value added initiatives.

Competitive Conditions

The petroleum and natural gas industry is competitive in all its phases. The Corporation must compete in all aspects of its operations with a substantial number of other companies, many of which have greater technical and/or financial resources. With the maturing nature of the Western Canadian Sedimentary Basin, the access to new prospects is becoming more and more competitive and complex.

Participants in the petroleum industry must manage risks beyond their direct control. Among these are risks associated with exploration, evolving environmental and operating regulations, commodity prices, royalty and tax rates, foreign exchange and interest rates.

The Corporation attempts to enhance its competitive position by operating in areas where it believes its technical personnel can reduce some of the risks associated with exploration, production and marketing because they are familiar with the areas of operation.

Health, Safety, Environmental and Social Policies

The Corporation's Corporate Code of Conduct, and Corporate Social Responsibility policies guide Altura's commitment to operating in a responsible manner. In 2020, Altura established an Environmental, Social and Governance committee and published its first sustainability report detailing its efforts and performance in health and safety, environmental management, and business and governance. These policies and the sustainability report are available on Altura's website at www.alturaenergy.ca.

Altura's management, employees and all contractors are responsible and accountable for the overall health, safety and environmental program of the Corporation. Altura 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.

Altura maintains a safe and environmentally responsible workplace and provides training, equipment and procedures to all individuals in adhering to its policies. It also solicits and takes into consideration input from neighbors, communities and other stakeholders in regard to protecting people and the environment.

The Corporation has an Emergency Response Plan ("**ERP**") which is prepared in accordance with applicable regulations. The ERP is designed to provide the policies, practices and procedures to be implemented in the event of an emergency situation that arises at or as a result of Altura's operations, including but not limited to: a serious injury or fatality, fire or explosion, uncontrolled or hazardous product release and oil or hazardous chemical spill. The purpose of the ERP is to protect the health, safety and welfare of the public and workers and minimize the potential adverse environmental effects. On an annual basis, Altura holds a functional tabletop ERP exercise in Alberta to test its understanding and effectiveness in the case of an actual emergency. In addition, Altura holds exercises annually to ensure that its staff and executives are ready should the need arise.

Cyclical Nature of Business

The Corporation's business is often driven by weather conditions and the health of the economy. Demand for crude oil and natural gas rises and falls with the strength of the economy as well as with the cold in the winters and the heat in the summers. This occurs both on a continental as well as global level. A strong economy may create higher commodity prices, which in turn may result in a greater amount of capital that the Corporation can expend on its capital program. A weak economy has the opposite effect. Cold winters and hot summers generally result in extra demand for natural gas on a continental basis, which in turn increase natural gas prices. In addition, the exploration for and the development of crude oil and natural gas reserves is dependent on access to areas where drilling is to be conducted. Seasonal weather variation, including "freeze-up" and "break-up", affect access in certain circumstances.

STATEMENT OF RESERVES DATA

The report on reserves data by McDaniel in Form 51-101F2 of NI 51-101 and the report of management and directors on reserves data and other information in Form 51-101F3 of NI 51-101 are attached as Appendix "A" and "B" to this AIF, respectively.

Disclosure of Reserves Data

The reserves data set forth below (the "**Reserves Data**") was prepared by McDaniel, the Corporation's independent qualified reserves evaluator, with an effective date of December 31, 2020 and a preparation date of April 14, 2021. The Reserves Data summarizes the crude oil, NGLs and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using forecast prices and costs.

The McDaniel Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and the COGE Handbook. Additional information not required by NI 51-101 has been presented to provide continuity and additional information, which the Corporation believes is important to readers of this AIF. McDaniel was engaged to provide evaluations of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of Altura's consolidated reserves are onshore in Canada and, specifically, in the Province of Alberta.

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

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

Altura determined the future net revenue and present value of future net revenue after income tax expenses by utilizing McDaniel's before income tax future net revenue and the Corporation's estimate of income tax. Altura's estimates of the after-income tax value of future net revenue have been prepared based on before income tax reserves information and include assumptions and estimates of the Corporation's tax pools and the sequences of claims and rates of claim thereon. The values shown may not be representative of future income tax obligations, applicable tax horizon or after-tax valuation. The after-tax net present value of Altura's crude oil and natural gas properties reflects the tax burden of its properties on a stand-alone basis. It does not provide an estimate of the value of the Corporation as a business entity, which may be significantly different. Altura's consolidated financial statements and management's discussion and analysis for the year ended December 31, 2020 should be consulted for additional information regarding the Corporation's taxes.

There are numerous uncertainties inherent in estimating quantities of crude oil, NGLs and natural gas reserves and the future cash flows attributed to such reserves. In general, such estimates 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 crude oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable crude oil, NGLs 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 consolidated reserves will vary from estimates thereof and such variations could be material.

It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to reserves estimated by McDaniel represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of crude 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 information relating to the Corporation's consolidated crude oil, NGLs and natural gas reserves contains forward-looking statements relating to future net revenues, forecast capital expenditures, future development plans, timing and costs related thereto, forecast operating costs, anticipated production and abandonment costs. See "*Note Regarding Forward-Looking Statements*", "*Industry Conditions*" and "*Risk Factors*".

In certain of the tables set forth below, the columns may not add due to rounding.

Reserves Data *(Forecast Prices and Costs)*

Altura Energy Inc.
Summary of Oil and Gas Reserves
Forecast Prices and Costs as of December 31, 2020
Total Reserves
Total Company

Table F1-1

	Light Crude & Medium Crude Oil		Heavy Crude Oil		Conventional Natural Gas		Natural Gas Liquids	
Reserves Category	**Gross (1) Mbbl**	**Net (2) Mbbl**	**Gross (1) Mbbl**	**Net (2) Mbbl**	**Gross (1) MMcf**	**Net (2) MMcf**	**Gross (1) Mbbl**	**Net (2) Mbbl**
Proved								
Developed Producing	164.5	137.6	562.8	508.5	3,439.0	3,142.8	100.3	89.1
Developed Non-Producing	11.4	9.5	83.5	77.9	252.7	235.9	7.3	6.7
Undeveloped	0.0	0.0	2,559.0	2,277.6	8,034.1	7,205.7	233.0	203.5
Total Proved	**176.0**	**147.1**	**3,205.4**	**2,863.9**	**11,725.8**	**10,584.4**	**340.6**	**299.3**
Total Probable	**67.3**	**56.8**	**2,439.2**	**2,128.6**	**12,491.8**	**11,174.6**	**362.8**	**306.6**
Total Proved + Probable	**243.3**	**203.9**	**5,644.7**	**4,992.5**	**24,217.6**	**21,758.9**	**703.4**	**606.0**

(1) Gross reserves are working interest reserves before royalty deductions.
(2) Net reserves are working interest reserves after royalty deductions plus royalty interest reserves.

Altura Energy Inc.
Summary of Net Present Value of Future Net Revenue
Forecast Prices and Costs as of December 31, 2020
Total Reserves
Total Company

Table F1-2

	Net Present Values of Future Net Revenue										
	Before Income Taxes Discounted at (%/year)					After Income Taxes Discounted at (%/year)					Unit Value Before Tax (1)
Reserves Category	@0.0% M$	@5.00% M$	@10.00% M$	@15.00% M$	@20.00% M$	@0.0% M$	@5.00% M$	@10.00% M$	@15.00% M$	@20.00% M$	@10% (1) ($/BOE)
Proved											
Developed Producing	8,968.9	10,540.0	10,604.1	10,181.4	9,630.7	8,968.9	10,540.0	10,604.1	10,181.4	9,630.7	8.42
Developed Non-Producing	1,756.0	1,562.7	1,391.5	1,243.6	1,116.3	1,756.0	1,562.7	1,391.5	1,243.6	1,116.3	10.42
Undeveloped	27,544.7	19,555.7	13,565.6	9,122.3	5,822.6	26,241.3	18,573.6	12,813.9	8,538.8	5,363.7	3.68
Total Proved	**38,269.6**	**31,658.4**	**25,561.2**	**20,547.3**	**16,569.6**	**36,966.2**	**30,676.3**	**24,809.5**	**19,963.8**	**16,110.7**	**5.04**
Total Probable	**60,816.8**	**43,540.0**	**31,887.2**	**23,914.6**	**18,339.6**	**47,225.6**	**33,408.2**	**24,129.1**	**17,840.3**	**13,493.7**	**7.32**
Total Proved + Probable	**99,086.5**	**75,198.4**	**57,448.5**	**44,461.9**	**34,909.1**	**84,191.8**	**64,084.5**	**48,938.6**	**37,804.1**	**29,604.4**	**6.09**

(1) The unit values are based on net reserve volumes.

Altura Energy Inc.
Total Future Net Revenue (Undiscounted)
Forecast Prices and Costs as of December 31, 2020
Total Reserves
Total Company

Table F1-3

Reserves Category	Revenue (1) M$	Royalties (2) M$	Operating Costs M$	Development Costs M$	Abandonment & Reclamation Costs M$	Future Net Revenue Before Income Taxes M$	Income Taxes M$	Future Net Revenue After Income Taxes M$
Total Proved Reserves	203,459	22,091	73,807	59,611	9,682	38,270	1,303	36,966
Total Proved + Probable Reserves	379,890	43,834	136,600	89,049	11,321	99,087	14,895	84,192

(1) Includes all product revenues and other revenues as forecast.
(2) Royalties include any net profits interests paid, as well as the Saskatchewan Corporation Capital Tax Surcharge.

Altura Energy Inc.
Future Net Revenue by Product Type
Forecast Prices and Costs as of December 31, 2020
Total Reserves
Total Company

Table F1-4

Reserves Category	Product Type	Future Net Revenue Before Income Taxes (discounted @ 10%) M$	Unit Value (1) $/Mcf $/bbl
Total Proved Reserves	Light Crude & Medium Crude Oil (Including Solution Gas and By-products)	1,707	11.60
	Heavy Crude Oil (Including Solution Gas and By-products)	23,854	8.33
	Conventional Natural Gas (Including By-products)		
	Tight Oil (Including Solution Gas and By-products)		
	Shale Gas (Including By-products)		
	Total	**25,561**	
Total Proved + Probable Reserves	Light Crude & Medium Crude Oil (Including Solution Gas and By-products)	2,142	11.75
	Heavy Crude Oil (Including Solution Gas and By-products)	54,661	10.95
	Conventional Natural Gas (Including By-products)	645	1.99
	Tight Oil (Including Solution Gas and By-products)		
	Shale Gas (Including By-products)		
	Total	**57,448**	

(1) Unit values are calculated using the 10% discount rate divided by the Major Product Type Net reserves for each group.

Pricing Assumptions – Forecast Prices and Costs

Weighted average historical prices Altura realized for the year ended December 31, 2020, were $36.59/Bbl for heavy oil, $36.21/Bbl for light crude oil and medium crude oil, $2.43/Mcf for natural gas and $21.32/Bbl for NGLs. McDaniel employed the following pricing, exchange rate and inflation rate assumptions as of December 31, 2020 in the McDaniel Report in estimating reserves data using forecast prices and costs. Benchmark weighted average historical prices for 2020 are also reflected in the tables below.

3 Consultant Average (McDaniel, GLJ and Sproule)

Summary of Price Forecasts
January 1, 2021

	Crude Oil Price Forecasts							Liquids Price Forecasts				Gas Price Forecasts									
Year	WTI Crude Oil $US/bbl (1)	Brent Crude Oil $US/bbl (2)	Edmonton Light Crude Oil $C/bbl (3)	Alberta Bow River Hardisty Crude Oil $C/bbl (4)	Western Canadian Select Crude Oil $C/bbl (5)	Alberta Heavy Crude Oil $C/bbl (6)	Sask Cromer Medium Crude Oil $C/bbl (7)	Edmonton Ethane $/bbl	Edmonton Propane $/bbl	Edmonton Butanes $/bbl	Edmonton Cond. & Natural Gasolines $/bbl	U.S. Henry Hub Gas Price $US/MMBtu	Alberta AECO Spot Price $C/MMBtu (8)	Alberta Average Plantgate $C/MMBtu (9)	Alberta Aggregator Plantgate $C/MMBtu	Empress $C/MMBtu	Sask. Prov. Gas Plantgate $C/MMBtu	British Columbia Average Plantgate $C/MMBtu	British Columbia Station 2 $C/MMBtu	Inflation %	US/CAN Exchange Rate $US/$CAN
History																					
2010	79.55	79.90	77.50	68.50	67.25	61.45	73.80		46.80	66.05	84.25	4.40	4.15	3.90	3.85		3.95	3.90		1.75	0.970
2011	95.10	111.25	95.05	78.55	77.10	67.90	89.05		55.15	76.50	104.20	4.00	3.70	3.50	3.75	3.50	3.55	3.30	3.40	2.90	1.010
2012	94.20	111.65	86.10	74.35	73.10	63.65	82.10		28.60	69.55	100.80	2.75	2.45	2.25	2.25	2.30	2.30	2.25	2.40	1.55	1.000
2013	97.95	108.60	93.05	76.55	75.25	65.25	88.25		38.90	69.40	104.65	3.75	3.20	3.00	3.00	3.10	3.10	2.95	3.10	0.95	0.970
2014	93.00	99.00	93.50	80.40	79.10	71.20	87.80		45.05	69.60	102.40	4.35	4.40	4.20	4.20	4.55	4.40	4.05	4.20	1.90	0.905
2015	48.80	52.35	57.75	46.10	44.80	39.55	51.45		6.60	36.50	60.30	2.60	2.80	2.60	2.60	3.00	2.70	2.00	2.10	1.10	0.785
2016	43.30	43.55	53.90	40.45	39.15	33.35	49.10		13.15	34.35	56.15	2.50	2.10	1.90	1.90	2.30	2.20	1.55	1.65	1.45	0.755
2017	50.90	54.25	62.85	52.00	50.70	45.20	59.85		28.90	44.60	66.85	3.00	2.40	2.20	2.20	2.85	2.40	1.80	1.95	1.60	0.770
2018	64.95	71.05	69.65	51.25	49.95	40.00	70.20		27.55	32.80	79.20	3.05	1.55	1.35	1.35	3.00	1.60	1.20	1.40	2.25	0.770
2019	57.00	64.35	69.00	60.00	58.70	54.80	68.00		17.40	23.55	70.30	2.55	1.60	1.40	1.40	2.75	1.75	1.00	1.15	2.00	0.755
2020	39.20	41.75	45.00	36.45	35.35	30.70	43.70		16.35	22.20	49.15	2.05	2.25	2.05	2.05	2.30	2.45	2.05	2.20	0.20	0.745
Forecast																					
2021	47.17	49.42	55.76	45.36	44.63	39.87	53.77	8.91	18.18	26.36	59.24	2.83	2.78	2.58	2.58	3.04	2.68	2.52	2.71	0.0	0.768
2022	50.17	52.85	59.89	48.96	48.18	43.20	57.31	8.65	21.91	32.85	63.19	2.87	2.70	2.50	2.50	2.99	2.60	2.42	2.62	1.3	0.765
2023	53.17	56.04	63.48	52.91	52.10	46.86	60.68	8.35	24.57	39.20	67.34	2.90	2.61	2.41	2.41	2.93	2.51	2.34	2.53	2.0	0.763
2024	54.97	57.87	65.76	54.95	54.10	48.67	62.90	8.46	25.47	40.65	69.77	2.96	2.65	2.44	2.44	2.97	2.54	2.37	2.56	2.0	0.763
2025	56.07	59.00	67.13	56.05	55.19	49.65	64.22	8.63	26.00	41.50	71.18	3.02	2.70	2.49	2.49	3.03	2.59	2.42	2.61	2.0	0.763
2026	57.19	60.15	68.53	57.16	56.29	50.65	65.57	8.81	26.54	42.36	72.61	3.08	2.76	2.54	2.54	3.09	2.65	2.47	2.67	2.0	0.763
2027	58.34	61.33	69.95	58.30	57.42	51.67	66.94	8.99	27.09	43.24	74.07	3.14	2.81	2.59	2.59	3.15	2.70	2.52	2.72	2.0	0.763
2028	59.50	62.53	71.40	59.47	58.57	52.71	68.35	9.17	27.65	44.14	75.56	3.20	2.87	2.64	2.64	3.21	2.75	2.57	2.77	2.0	0.763
2029	60.69	63.75	72.88	60.66	59.74	53.76	69.78	9.36	28.23	45.06	77.08	3.26	2.92	2.69	2.69	3.28	2.81	2.62	2.83	2.0	0.763
2030	61.91	65.03	74.34	61.87	60.93	54.84	71.19	9.54	28.79	45.96	78.62	3.33	2.98	2.74	2.74	3.34	2.86	2.68	2.88	2.0	0.763
2031	63.15	66.33	75.83	63.10	62.15	55.94	72.61	9.74	29.37	46.88	80.20	3.39	3.04	2.80	2.80	3.41	2.92	2.73	2.94	2.0	0.763
2032	64.41	67.66	77.34	64.37	63.40	57.05	74.06	9.93	29.95	47.82	81.80	3.46	3.10	2.85	2.85	3.48	2.98	2.79	3.00	2.0	0.763
2033	65.70	69.01	78.89	65.65	64.66	58.20	75.55	10.13	30.55	48.77	83.44	3.53	3.16	2.91	2.91	3.55	3.04	2.84	3.06	2.0	0.763
2034	67.01	70.39	80.47	66.97	65.96	59.36	77.06	10.33	31.16	49.75	85.10	3.60	3.23	2.97	2.97	3.62	3.10	2.90	3.12	2.0	0.763
2035	68.35	71.80	82.08	68.31	67.28	60.55	78.60	10.54	31.79	50.74	86.81	3.67	3.29	3.03	3.03	3.69	3.16	2.96	3.18	2.0	0.763
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	0.763

(1) West Texas Intermediate at Cushing Oklahoma 40 degrees API, 0.5% sulphur
(2) North Sea Brent Blend 37 degrees API, 1.0% sulphur
(3) Edmonton Light Sweet 40 degrees API, 0.3% sulphur
(4) Bow River at Hardisty, Alberta (Heavy stream)
(5) Western Canadian Select at Hardisty, Alberta
(6) Heavy crude oil 12 degrees API at Hardisty, Alberta (after deduction of blending costs to reach pipeline quality)
(7) Midale Cromer crude oil 29 degrees API, 2.0% sulphur
(8) Historical prices based on AECO 7A (near month prices). 5A (daily price) expected to be equal to 7A over long term. 2019 historical prices: 7A $1.60/MMBTU, 5A $1.75/MMBTU
(9) This forecast also applies to direct sales contracts and the Alberta gas reference price used in the Crown royalty calculations

Reconciliation of Changes in Reserves

The following table sets forth a reconciliation of the Corporation's gross reserves as at December 31, 2020, derived from the McDaniel Report using forecast prices and cost estimates, reconciled to the Corporation's gross reserves as at December 31, 2019.

Reconciliation of Company Gross Reserves[1] by Product Type[2]
Forecast Prices and Costs as of December 31, 2020
Total Reserves
Total Company

	Light Crude & Medium Crude Oil (Mbbl)	Heavy Crude Oil (Mbbl)	Conventional Natural Gas (MMcf)	Natural Gas Liquids (Mbbl)	Oil Equivalent (MBoe)
Total Proved					
December 31, 2019	161.2	3,695.0	13,052.0	315.1	6,346.5
Extensions and improved recovery[3]	11.4	-	-	-	11.4
Technical Revisions[4]	49.5	(13.6)	889.3	85.7	269.7
Acquisitions	-	-	-	-	-
Dispositions[5]	(7.4)	(125.6)	(518.3)	(15.1)	(234.5)
Economic Factors	(8.9)	(207.8)	(910.1)	(26.4)	(394.8)
Production[6]	(29.8)	(142.6)	(787.1)	(18.6)	(322.1)
December 31, 2020	**176.0**	**3,205.4**	**11,725.8**	**340.7**	**5,676.2**
Total Probable					
December 31, 2019	164.2	2,336.6	12,109.9	284.6	4,803.9
Extensions and improved recovery[3]	3.2	509.1	1,967.9	57.1	897.4
Technical Revisions[4]	(88.4)	(236.6)	(591.8)	49.9	(373.8)
Acquisitions	-	-	-	-	-
Dispositions[5]	(2.3)	(66.3)	(344.2)	(9.9)	(135.8)
Economic Factors	(9.5)	(103.6)	(649.7)	(18.9)	(240.3)
Production[6]	-	-	-	-	-
December 31, 2020	**67.2**	**2,439.2**	**12,491.8**	**362.8**	**4,951.4**
Total Proved + Probable					
December 31, 2019	325.4	6,031.6	25,161.9	599.7	11,150.4
Extensions and improved recovery[3]	14.6	509.1	1,967.9	57.1	908.8
Technical Revisions[4]	(38.9)	(250.2)	297.5	135.6	(104.1)
Acquisitions	-	-	-	-	-
Dispositions[5]	(9.7)	(191.9)	(862.5)	(25.0)	(370.3)
Economic Factors	(18.4)	(311.4)	(1,559.8)	(45.3)	(635.1)
Production[6]	(29.8)	(142.6)	(787.4)	(18.6)	(322.1)
December 31, 2020	**243.2**	**5,644.6**	**24,217.6**	**703.5**	**10,627.6**

(1) Gross reserves are Company working interest reserves before royalty deductions.
(2) Numbers may not add due to rounding.
(3) Extensions and Improved Recovery includes all new wells booked during the year at Leduc-Woodbend and a planned optimization within the Leduc-Woodbend Glauconitic Unit.
(4) Negative technical revisions were realized in both proved and probable heavy crude oil reserve categories. The revisions are larger in the probable category and were driven by performance deviations from earlier estimates on the probable additional performance of the proved developed reserves. Positive revisions were realized in both proved and probable conventional natural gas and NGL reserve categories. These revisions were driven by higher than previously forecasted gas to oil ratios in the Leduc-Woodbend area.
(5) The dispositions amount relates to the 1.375% asset disposition on June 30, 2020 and the 1.375% asset disposition on September 30, 2020.
(6) Altura produced an average of 880 Boe per day in 2020.

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

Undeveloped reserves are attributed by McDaniel in accordance with standards and procedures contained in the COGE Handbook. 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.

Proved Undeveloped Reserves

The following table discloses, for each product type, the volumes of proved undeveloped reserves that were first attributed in each of the most recent three financial years.

Year	Light Crude & Medium Crude Oil (Mbbl)		Heavy Crude Oil (Mbbl)		Conventional Gas (MMcf)		Natural Gas Liquids (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2018	-	-	2,778.1	3,107.7	6,046.7	6,764.6	151.2	169.1
2019	-	-	204.5	2,815.4	615.7	8,473.9	14.8	203.4
2020	-	-	-	2,559.0	-	8,034.0	-	233.0

Proved undeveloped reserves have been assigned in areas where the reserves can be estimated with a high degree of certainty. In most instances, proved undeveloped reserves will be assigned on lands immediately offsetting existing producing wells within the same accumulation or pool. McDaniel has assigned 4,131.1 Mboe of proved undeveloped reserves in the McDaniel Report with $58.6 million of associated undiscounted capital, of which $19.0 million is forecast to be spent in the first two years.

The Corporation's proved undeveloped reserves are in its core area where Altura is actively spending capital to develop the Leduc-Woodbend property. As such, the Corporation expects that most of its booked undeveloped projects will be completed within a three-year time frame and that substantially all of its currently booked undeveloped projects will be completed within a four-year time frame. There are a number of factors that could result in delayed or cancelled development, including the following: (i) existence of higher priority expenditures; (ii) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (iii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iv) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (v) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (vi) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "*Risk Factors"* herein.

Probable Undeveloped Reserves

The following table discloses, for each product type, the volumes of probable undeveloped reserves that were first attributed in each of the most recent three financial years.

Year	Light Crude & Medium Crude Oil (Mbbl)		Heavy Crude Oil (Mbbl)		Conventional Gas (MMcf)		Natural Gas Liquids (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2018	-	-	2,083.6	2,203.6	4,949.9	5,249.4	123.7	131.2
2019	111.1	111.1	316.9	1,990.1	1,635.3	10,019.7	32.7	233.9
2020	-	-	509.1	2,268.2	1,967.9	11,062.8	894.2	320.8

Probable undeveloped reserves have been assigned in areas where the reserves can be estimated with less certainty. It is equally likely that the actual remaining quantities recovered will be greater or less than the proved and probable reserves. In most instances, probable undeveloped reserves have been assigned on lands in the area with existing producing wells but there is some uncertainty as to whether they are directly analogous to the producing accumulation or pool. McDaniel has assigned 4,432.8 Mboe of probable undeveloped reserves in the McDaniel Report with $29.3 million of associated undiscounted capital, of which no capital is forecasted to be spent in the first two years.

The Corporation's probable undeveloped reserves are in its core area of Leduc-Woodbend. Altura is actively spending capital to develop the area. As such, the Corporation expects that substantially all of its currently booked undeveloped projects will be completed within a five-year time frame.

Significant Factors or Uncertainties Affecting Reserves Data

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting crude oil and natural gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present value of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) timing and costs of future development activities; (vii) marketability of production; (viii) effects of government regulations; and (ix) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and government restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

While Altura does not anticipate any significant economic factors or significant uncertainties that will affect any particular components of the reserves data, the reserves can be affected significantly by fluctuations in product pricing, capital expenditures, costs to abandon and reclaim properties, operating costs, royalty regimes and well performance that are beyond the Corporation’s control.

Abandonment and Reclamation Costs

In connection with its operations, the Corporation will incur abandonment and reclamation costs for surface leases, wells, facilities and pipelines. Altura budgets for and recognizes as a liability the estimated present value of the future decommissioning liabilities associated with its property, plant and equipment. Altura's overall abandonment and reclamation costs include all costs associated with the process of restoring a property that has been disturbed by oil and gas activities to the standard imposed by the applicable government or regulatory authorities. The Corporation estimates such costs through a model that incorporates data from Altura's operating history, industry sources and cost formulas used by AER, together with other operating assumptions. The Corporation expects all of its net wells to incur these costs.

Altura anticipates the total amount of such costs, excluding inflation, to be approximately $5.4 million ($7.0 million including inflation) on an undiscounted basis, and approximately $2.0 million discounted at 10% and assuming an inflation rate of 2%, calculated in accordance with NI 51-101.

All existing and future abandonment and reclamation costs are reflected in McDaniel's estimate of future net revenue. The calculations of future net revenue associated with proved plus probable reserves under "Oil and Natural Gas Reserves" in this Annual Information Form include expenditures of approximately $4.2 million (on an undiscounted basis) and $0.5 million (discounted at 10%) in respect of the abandonment and reclamation of future wells and facilities where that obligation has not yet been incurred but is expected to be incurred.

Over the next three years, the Corporation does not anticipate any spending in respect of abandonment and reclamation costs.

Future Development Costs

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

	FORECAST PRICES AND COSTS	
($000s)	**Total Proved Reserves**	**Total Proved Plus Probable Reserves**
2021	4,947	4,947
2022	15,111	15,261
2023	21,843	26,060
2024	17,710	32,255
2025	-	10,526
Thereafter	-	-
Total for all years undiscounted	59,611	89,049
Total for all years discounted at 10% per year	48,260	69,420

Altura expects to use a combination of internally generated cash from operating activities, its Credit Facility and the issuance of new equity or debt where and when it believes appropriate to fund future development costs set out in the McDaniel Report. There can be no guarantee that funds will be available or that the Board of Directors will allocate funding to develop all the reserves attributable in the McDaniel Report. Failure to develop those reserves could have a negative impact on the Corporation's future cash flow.

Interest expense or other costs of external funding are not included in the reserves and future net revenue estimates set forth above and would reduce the reserves and future net revenue to some degree depending upon the funding sources utilized. The Corporation does not anticipate that interest or other funding costs would make further development of any of the Corporation's properties uneconomic.

OTHER OIL AND NATURAL GAS INFORMATION

Principal Properties

Leduc-Woodbend

The Corporation has two producing properties in the Leduc-Woodbend area of central Alberta, located approximately 10 kilometers southwest of Leduc, Alberta. On December 4, 2019, June 30, 2020, and September 30, 2020 the Corporation divested of a 7% working interest, a 1.375% working interest and a 1.375% working interest, respectively, in the production, wells, lands and facilities as described in *"General Development of the Business"* of this AIF, in both producing assets.

Leduc-Woodbend Rex Pool

The majority of the Corporation's development and production activities in the Leduc-Woodbend area are directed towards 17° API heavy crude oil in the Rex member of the Upper Mannville Formation ("**Leduc-Woodbend**").

At December 31, 2020, Altura held a 89% working interest in 44,353 acres of land at Leduc-Woodbend, of which 25,159 net acres are undeveloped and 14,352 net acres are developed. Altura completed, equipped and brought one (0.9 net) horizontal well on production in 2020 that was drilled in 2019 and drilled one (0.9 net) horizontal well that was completed and brought on production in the first quarter of 2021. McDaniel assigned 5,486.0 Mboe of proved reserves and 10,293.2 Mboe of proved plus probable reserves at Leduc-Woodbend in the McDaniel Report.

During the year ended December 31, 2020, Altura had average production of 792 Boe/d (including 389 Bbls/d of heavy oil, 50 Bbls/d of NGLs and 2,119 Mcf/d of natural gas) from 16 producing wells. Production in the area is tied into two multi-well batteries and two single well batteries owned and operated by the Corporation. Crude oil sales volumes are trucked to multiple sales points and natural gas production is transported via pipeline and processed by two third-party operators.

Leduc-Woodbend Glauconitic D Unit No.1

The Corporation has a minor property in the Leduc-Woodbend area directed towards 33° API light crude oil in the *Glauconitic D Unit No.1* (the "**Glauc Unit**").

At December 31, 2020, Altura held a 54.1% working interest in 1,920 acres of land in the Glauc Unit, of which all 1,038 net acres are developed. McDaniel assigned 190.3 Mboe of proved reserves and 236.4 Mboe of proved plus probable reserves in the Glauc Unit in the McDaniel Report.

During the year ended December 31, 2020, Altura had average production of approximately 82 Boe/d (including 76 Bbls/d of heavy oil, one Bbl/d of NGLs and 32 Mcf/d of natural gas) from seven producing wells. Production in the area is tied into a 54.1% working interest multi-well battery, operated by the Corporation. Light crude oil from the Glauc Unit is blended with heavy crude oil from the Leduc-Woodbend Rex Pool and is sold into the heavy oil stream. The blended crude oil sales volumes are trucked to multiple sales points and natural gas production is transported via pipeline and processed by a third-party operator.

Entice Area

The Entice area of southern Alberta is located approximately nine kilometers south of Strathmore, Alberta. In December 2019, June 30, 2020, and September 30, 2020 the Corporation divested of a 7% working interest, a 1.375% working interest and a 1.375% working interest, respectively, in the area's lands as described in *"General Development of the Business"* of this AIF. At December 31, 2020, Altura held a 90.25% working interest in 57,485 acres of land in the Entice Area, of which 438 net acres are developed. McDaniel assigned 98.0 Mboe of probable reserves in the Entice area in the McDaniel Report.

In the first quarter of 2020, Altura drilled, completed and equipped an exploratory horizontal well at 13-24-023-25W4 ("**13-24 Well**") in the Entice area of Alberta. From March 5, 2020 to March 19, 2020, the 13-24 Well produced 645 barrels of medium crude oil, 6.5 MMcf of natural gas (which was flared) and 4,500 barrels of water. Approximately 73% of the total water used in the completion was recovered during that period. The 13-24 Well was shut-in on March 19, 2020 because of the decline in crude oil prices due to the COVID-19 pandemic.

The 13-24 Well was restarted in June 2020 to resume the production test but was shut-in in August 2020 to manage gas conservation requirements as natural gas rates exceeded allowable flaring limits. Management is assessing natural gas tie-in options for the 13-24 Well.

Oil and Natural Gas Wells

The following table sets forth the number and status of the Corporation's wells effective December 31, 2020.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	22	17.6	40	27.2	-	-	-	-
Total	22	17.6	40	27.2	-	-	-	-

Notes:

(1) "Gross" wells means the number of wells in which the Corporation has a working interest.

(2) "Net" wells means the aggregate number of wells obtained by multiplying each gross well by the Corporation's percentage working interest therein.

Properties With No Attributed Reserves

The following table summarizes, effective December 31, 2020, the gross and net acres of undeveloped properties in which the Corporation had an interest and also the number of net acres for which its rights to explore, develop or exploit are expected to expire within one year.

	Gross Acres	Net Acres	Net Acres Expiring Within One Year
Canada	85,286	77,015	48,444
Total	85,286	77,015	48,444

On March 31, 2021, Altura allowed 45,405 net acres in the Entice area to expire.

Significant Factors or Uncertainties Relevant to Properties With No Attributed Reserves

There are several economic factors and significant uncertainties that affect the anticipated development of Altura's properties with no attributed reserves. The Corporation will be required to make substantial capital expenditures in order to exploit, develop, prove and produce crude oil and natural gas from these properties in the future. If Altura's cash flow is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to the Corporation. Failure to obtain such financing on a timely basis could cause Altura to forfeit its interest in certain properties, miss certain opportunities and reduce or terminate its operations. The inability of Altura to access sufficient capital for its exploration and development activities could have a material adverse effect on Altura's ability to execute its business strategy to develop these prospects.

The significant economic factors that affect Altura's development of its lands to which no reserves have been attributed are future commodity prices for crude oil and natural gas and Altura's outlook relating to such prices, and the future costs of drilling, completing, equipping, tie-in and operating the wells at the time that such activities are considered in the future.

The significant uncertainties that affect Altura's development of such lands are: (i) the future drilling and completion results Altura achieves in its development activities; (ii) drilling and completion results achieved by others on lands in proximity to Altura's lands; and (iii) future changes to applicable regulatory or royalty regimes that affect timing or economics of proposed development activities. All of these uncertainties have the potential to delay the development of such lands. Alternatively, uncertainty as to the timing and nature of the evolution or development of improved exploration drilling, completion and production technologies has the potential to accelerate development activities and enhance the economics relating to such lands.

Forward Contracts

The Corporation’s financial results and condition are impacted primarily by the prices received for crude oil, natural gas and NGLs production. Crude oil, natural gas and NGLs prices have fluctuated widely and are determined by supply and demand factors, including available access to pipelines and markets, weather, general economic conditions in natural gas consuming and producing regions throughout North America and political factors. Any upward or downward movement in crude oil, NGLs and natural gas prices could have an effect on the Corporation's financial condition and capital development.

Altura's hedging transactions are approved by the Board of Directors and may include fixed price swaps, costless collars and put options to hedge a portion of its gross crude oil or natural gas production. To the extent that the Corporation engages in risk management activities related to commodity prices, it will be subject to credit risk associated with the parties with which it contracts. This credit risk will be mitigated by entering into contracts with only stable and creditworthy parties and through the frequent review of the Corporation's exposure to these entities.

At December 31, 2020, Altura held the following crude oil and natural gas contracts:

Period	Commodity	Type of Contract	Quantity	Pricing Point	Contract Price
Jan 1/21—Jun 30/21	Crude Oil	Fixed	100 Bbls/d	WCS	CAD $32.25
Jan 1/21—Jun 30/21	Crude Oil	Fixed	100 Bbls/d	WCS	CAD $39.20
Jul 1/21—Sep 30/21	Crude Oil	Fixed	200 Bbls/d	WCS	CAD $36.70
Oct 1/21—Dec 31/21	Crude Oil	Fixed	100 Bbls/d	WCS	CAD $37.70
Oct 1/21—Dec 31/21	Crude Oil	Fixed	100 Bbls/d	WCS	CAD $39.70
Jan 1/21—Mar/21	Natural Gas	Fixed	1,000 GJ/d	AECO 5A	CAD $2.825
Apr 1/21—Jun 30/21	Natural Gas	Fixed	1,000 GJ/d	AECO 5A	CAD $2.455
Jul 1/21—Sep 30/21	Natural Gas	Fixed	1,000 GJ/d	AECO 5A	CAD $2.580
Oct 1/21—Dec 31/21	Natural Gas	Fixed	1,000 GJ/d	AECO 5A	CAD $2.545

Subsequent to December 31, 2020, Altura entered into the following crude oil and natural gas contracts:

Period	Commodity	Type of Contract	Quantity	Pricing Point	Contract Price
Jan 1/22–Jan 31/22	Crude Oil	Fixed	200 Bbls/d	WCS	CAD $51.00
Feb 1/22–Feb 28/22	Crude Oil	Fixed	125 Bbls/d	WCS	CAD $55.50
Jan 1/22–Jan 31/22	Natural Gas	Fixed	1,000 GJ/d	AECO 5A	CAD $2.72
Feb 1/22–Feb 28/22	Natural Gas	Fixed	750 GJ/d	AECO 5A	CAD $2.87
Jul 1/21–Jul 31/21	Natural Gas	Fixed	500 GJ/d	AECO 5A	CAD $2.64
Aug 1/21–Aug 31/21	Natural Gas	Fixed	1,000 GJ/d	AECO 5A	CAD $2.44
Sep 1/21–Sep 30/21	Natural Gas	Fixed	500 GJ/d	AECO 5A	CAD $2.60

Tax Horizon

Based on McDaniel production forecasts, planned capital expenditures and the forecast commodity pricing employed in the McDaniel Report, the Corporation estimates that it will not be required to pay current income taxes until 2024.

Costs Incurred

The following table summarizes capital expenditures, excluding property dispositions, incurred by the Corporation during the year ended December 31, 2020.

	Property Acquisitions			
($000s)	**Proved Properties**	**Unproved Properties**	**Exploration Costs**	**Development Costs**
Total	-	-	4,008	3,866

Drilling Activity

The following table sets forth the gross and net exploratory and development wells drilled by the Corporation during the year ended December 31, 2020. All wells were drilled in Canada.

	Exploratory Wells		Development Wells	
	Gross	**Net**	**Gross**	**Net**
Crude Oil	1	1	1	0.9
Natural Gas	-	-	-	-
Service	-	-	-	-
Stratigraphic Test	-	-	-	-
Dry	-	-	-	-
Total	1	1.0	1	0.9

Planned Capital Expenditures

The board of directors of the Corporation has approved a capital budget of $6.0 million for 2021, funded with forecasted cash flow from operating activities, available Credit Facilities, and the 2021 asset dispositions. The budget includes drilling two (1.8 net) Rex wells and completing three (2.7 net) Rex wells at Leduc-Woodbend.

Production Estimates

The following table discloses for each product type the total volume of production estimated by McDaniel in the McDaniel Report for 2021 in the estimates of future net revenue from gross proved and gross proved plus probable reserves disclosed above.

	Light Crude Oil & Medium Crude Oil Bbls/d	Heavy Crude Oil Bbls/d	Conventional Natural Gas Mcf/d	Natural Gas Liquids Bbls/d	Total Oil Equivalent Boe/d
PROVED					
Developed Producing	-	415	1,946	57	796
Developed Non-Producing	-	99	137	4	126
Undeveloped	-	86	76	2	101
TOTAL PROVED	-	600	2,159	63	1,023
TOTAL PROBABLE	-	27	119	3	50
TOTAL PROVED & PROBABLE	-	627	2,278	66	1,073

The estimated production volumes for the Leduc-Woodbend Rex Pool, which accounts for 91% of McDaniel's total forecast production for the year ending December 31, 2021, is set forth below.

	Leduc-Woodbend Total Oil Equivalent Boe/d
PROVED	
Developed Producing	711
Developed Non-Producing	118
Undeveloped	101
TOTAL PROVED	930
TOTAL PROBABLE	47
TOTAL PROVED & PROBABLE	977

Production History

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

	Quarter Ended 2020				Year Ended Dec. 31, 2020
	Mar. 31	**Jun. 30**	**Sep. 30**	**Dec. 31**	
Average Daily Production(1)					
Light Crude Oil and Medium Crude Oil (Bbls/d)(2)	8	-	16	-	6
Heavy Crude Oil (Bbls/d)	667	213	513	468	465
Conventional Natural Gas (Mcf/d)	2,926	1,154	2,118	2,402	2,151
NGLs (Bbls/d)	87	30	38	48	51
Combined (Boe/d)	1,250	435	919	916	880
Average Prices Received					
Light Crude Oil and Medium Crude Oil ($/Bbl) (2)	20.85	-	43.79	-	36.21
Heavy Crude Oil ($/Bbl)	33.06	21.39	40.19	44.45	36.59
Conventional Natural Gas ($/Mcf)	2.20	2.06	2.45	2.87	2.43
NGLs ($/Bbl)	22.02	6.46	25.83	25.72	21.32
Combined ($/Boe)	24.46	16.36	29.87	31.56	26.74
Royalties Paid					
Light Crude Oil and Medium Crude Oil ($/Bbl) (2)	2.37	-	3.04	-	2.82
Heavy Crude Oil ($/Bbl)	2.81	2.67	4.19	3.79	3.42
Conventional Natural Gas ($/Mcf)	0.12	(0.62)	0.06	0.20	0.03
NGLs ($/Bbl)	2.33	0.82	2.65	2.57	2.22
Combined ($/Boe)	1.96	(0.28)	2.63	2.61	2.03
Operating Expenses(3)					
Light Crude Oil and Medium Crude Oil ($/Bbl)	48.09	-	94.63	-	98.60
Heavy Crude Oil ($/Bbl)	11.96	15.33	12.44	12.69	12.66
Conventional Natural Gas ($/Mcf)	1.99	2.55	2.07	2.12	2.12
NGLs ($/Bbl)	11.96	15.33	12.44	12.69	12.72
Combined ($/Boe)	12.19	16.27	13.85	12.75	13.27
Transportation Expenses					
Light Crude Oil and Medium Crude Oil ($/Bbl)	-	-	-	-	-
Heavy Crude Oil ($/Bbl)	3.21	2.99	3.36	2.38	3.02
Conventional Natural Gas ($/Mcf)	0.32	0.35	0.26	0.25	0.29
NGLs ($/Bbl)	0.38	0.79	0.89	0.85	0.65
Combined ($/Boe)	2.49	2.46	2.51	1.93	2.34
Netback Received(4)					
Light Crude Oil and Medium Crude Oil ($/Bbl) (2)	(29.61)	-	(53.88)	-	(65.21)
Heavy Crude Oil ($/Bbl)	15.08	0.40	20.20	25.59	17.49
Conventional Natural Gas ($/Mcf)	(0.23)	(0.22)	0.06	0.30	(0.01)
NGLs ($/Bbl)	7.35	(10.48)	9.85	9.61	5.73
Combined ($/Boe)	7.82	(2.09)	10.88	14.27	9.10

Notes:

(1) Before the deduction of royalties.

(2) Light crude oil and medium crude oil relates to Altura's Entice area that produced intermittently during 2020. Light crude oil from Altura's Glauconitic Unit is blended with heavy crude oil from the Leduc-Woodbend Rex Pool and is sold into the heavy crude oil stream.

(3) The Corporation does not record operating expenses on a commodity basis. Information in respect of operating expenses for heavy crude oil and NGLs ($/Bbl) and natural gas ($/Mcf) has been determined by allocating expenses on a relative volume of heavy crude oil, NGLs and natural gas production basis.

(4) Netback is calculated by subtracting royalties, operating expenses and transportation expenses from prices received.

Production Volume by Field

The following table indicates the average daily net production from Altura's properties for the year ended December 31, 2020.

	Light Crude Oil & Medium Crude Oil (Bbls/d)	Heavy Crude Oil (Bbls/d)	Natural Gas Liquids (Bbls/d)	Conventional Natural Gas (Mcf/d)	Total Oil Equivalent (Boe/d)	Percentage (%)
Leduc-Woodbend Rex Pool	-	389	50	2,119	792	90
Leduc-Woodbend Glauconitic Unit[(1)]	-	76	1	32	82	9
Entice	6	-	-	-	6	1
Total	6	465	51	2,151	880	100

Notes:

(1) Altura's Glauconitic Unit produces light crude oil that is blended with heavy crude oil from the Leduc-Woodbend Rex Pool and is sold into the heavy crude oil stream.

MANAGEMENT OF THE CORPORATION

As at the date hereof, the name, municipality of residence and principal occupation of the directors and senior officers of the Corporation are as follows:

Name and Municipality of Residence	Position Held	Date First Elected or Appointed
David Burghardt[(4)] Calgary, Alberta	President, Chief Executive Officer and Director	July 31, 2015
Tavis Carlson Calgary, Alberta	Vice-President, Finance and Chief Financial Officer and Secretary	September 1, 2015
Travis Stephenson Calgary, Alberta	Vice-President, Engineering	July 31, 2015
Robert Pinckston Calgary, Alberta	Vice-President, Exploration	July 31, 2015
Jeff Mazurak Calgary, Alberta	Vice-President, Operations	July 31, 2015
Craig Stayura Calgary, Alberta	Vice-President, Land	March 22, 2017
John McAleer[(1)(2)(3)(4)] Calgary, Alberta	Director	July 31, 2015
Darren Gee[(1)(2)] Calgary, Alberta	Director	July 31, 2015
Robert Maitland[(1)(3)] Victoria, British Columbia	Director	July 31, 2015
John Chambers[(2)(3)(4)] Calgary, Alberta	Director	June 4, 2019

Notes:

(1) Member of the Audit Committee.
(2) Member of the Reserves Committee.
(3) Member of the Compensation Committee.
(4) Member of the Environmental, Social and Governance Committee.

As at the date hereof, the officers and directors, as a group, held, directly or indirectly, or exercise control or direction over 10,385,087 Common Shares representing 9.5% of the issued and outstanding Common Shares.

All of the Corporation's directors' terms of office will expire at the earliest of their resignation, the close of the next annual shareholder meeting called for the election of directors, or on such other date as they may be removed according to the ABCA. Each director will devote the amount of time as is required to fulfill his obligations to the Corporation. The Corporation's officers are appointed by and serve at the discretion of the Board of Directors.

Directors and Officers – Biographies

The following are brief profiles of the current directors and officers of the Corporation, including a description of each individual's principal occupation within the past five years.

David Burghardt, President, Chief Executive Officer and Director

Mr. Burghardt is a Professional Engineer with 34 years of multi-discipline domestic and international experience with a background in all industry functions, particularly asset exploitation, reservoir management and production engineering. Most recently, Mr. Burghardt was the Managing Director of the French Business Unit for Vermilion Energy Inc. ("**Vermilion**"). Stewarding production of approximately 11,000 Boe/d, he was responsible for a staff of 150 employees and approximately 350 contracting/consulting employees. Prior to this position, Mr. Burghardt was the Director Exploitation Europe and Manager Exploitation for Vermilion's French subsidiary based in southwest France.

Mr. Burghardt graduated from the University of Saskatchewan with a Bachelor of Science Degree in Chemical Engineering and is registered as a P.Eng. with the Association of Professional Engineers and Geoscientists of Alberta ("**APEGA**").

Tavis Carlson, Vice-President, Finance and Chief Financial Officer and Secretary

Mr. Carlson is a Chartered Professional Accountant with 19 years of financial and management experience, focused on public Canadian oil and gas companies. Mr. Carlson was Vice-President, Finance and Chief Financial Officer of Bellamont Exploration Ltd. from 2009 to 2012 and the Controller of Manitok Energy Inc. from 2012 to August 2015.

Mr. Carlson graduated from the University of Alberta in 2002 with a Bachelor of Commerce degree and has been a member of the Chartered Professional Accountants of Alberta (CA) since 2005.

Travis Stephenson, Vice-President, Engineering

Mr. Stephenson is a Professional Engineer with 21 years of engineering and management experience in the oil and gas sector. From 2010 to December 2014, Mr. Stephenson worked for Chinook Energy Inc. (originally named Storm Ventures International Inc.) ("**Chinook**") where he was VP Engineering, International as well as the Country Manager for Chinook's operations in Tunisia. During this period, Chinook's Tunisian production increased from 200 to 3,000 Boe/d. Mr. Stephenson managed a staff of 80 personnel and helped bring new technologies to Tunisia, such as horizontal wells and multi-stage hydraulic fracture completions.

Mr. Stephenson graduated from the University of Saskatchewan with a Bachelor of Science Degree in Mechanical Engineering and is registered as a P.Eng. with APEGA.

Robert Pinckston, Vice-President, Exploration

Mr. Pinckston has 32 years of exploration and development experience in the oil and gas industry. Mr. Pinckston was employed with Vermilion from 2010 to 2015. His most recent role was as Team Lead Conventional Exploration, in which his team was instrumental to the corporate evaluation and purchase of Elkhorn Resources Inc. in March 2014 for $400 million. Prior to that, he was Chief Geoscientist, where his role was to provide functional leadership to all geologists working on Vermilion's Canadian asset base and to ensure that a consistent and high level of technical work was being performed on all geologic activities within the Western Canadian Sedimentary Basin, including Vermilion's successful Cardium and liquids-rich Mannville programs in Drayton Valley.

Mr. Pinckston graduated with an MSc degree from the University of Alberta in 1989 and is registered as a Professional Geologist with APEGA.

Jeff Mazurak, Vice-President, Operations

Mr. Mazurak is a Professional Engineer with 17 years of oil and gas engineering and management experience. As a Production Engineering Manager at Bonavista Energy Corporation ("**Bonavista**"), Mr. Mazurak recently led the production, completion and field operations in the company's Deep Basin and Central Alberta assets. Such operations encompassed daily production of up to 47,000 Boe/d and annual capital expenditures of up to $350 million. Previously, he worked as a Production and Completions Engineer in various areas within Bonavista.

Mr. Mazurak started his career with EnCana Corporation where he initially worked as a Facilities Engineer and later as a Completions Engineer in the Deep Basin Business Unit, focused on Montney horizontal development and piloting various completion techniques on 40 to 60 wells per year.

Mr. Mazurak graduated from the University of Regina with a Bachelor of Science Degree in Petroleum Systems Engineering and is registered as a P.Eng. with APEGA.

Craig Stayura, Vice-President, Land

Mr. Stayura is a Landman with 14 years of industry experience. Most recently, as a negotiating landman for Mosaic Energy Ltd. ("**Mosaic**"), Mr. Stayura was responsible for the management, retention, evaluation and asset maximization of Mosaic's mineral rights.

Mr. Stayura started his career with ConocoPhillps Canada where he initially worked as a Jr. Landman, and later as an Area Landman in a number of areas within the organization.

Mr. Stayura graduated from the University of Calgary with a Bachelor of Commerce Degree in Petroleum Land Management and is an active member of the Canadian Association of Petroleum Landmen.

John McAleer, Director

Mr. McAleer is a Managing Director with Palisade Capital Management Ltd., a Calgary-based portfolio manager and investment fund manager. Prior thereto, he was President and Portfolio Manager of Andylan Capital Strategies Ltd. He has 30 years of experience in the Canadian energy sector in the areas of oil and gas operations, investment bank research, and private and public equity investment management. Mr. McAleer's previous positions have included Managing Director of Livingstone Energy Management, Managing Director of CanFund VE Management II Ltd., Vice President, Institutional Research with FirstEnergy Capital Corp., and Manager, Gas Projects with Renaissance Energy Ltd. ("**Renaissance**"). He earned a BSc in Mechanical Engineering from the University of Waterloo and is registered as a P.Eng. with APEGA and as a Portfolio Manager with the Alberta Securities Commission.

Darren Gee, Director

Mr. Gee is President, CEO and a director of Peyto Exploration & Development Corp. ("**Peyto**"), a natural gas weighted exploration and production company. He joined Peyto in 2001 as VP Engineering and assumed the role of CEO in 2007. Previously, Mr. Gee worked for Petro-Canada, Anderson Exploration Ltd., Renaissance and Husky Energy Inc.. Mr. Gee earned a BSc in Mechanical Engineering from the University of Alberta (1989) and is registered as a P.Eng. with APEGA.

Robert Maitland, Director

Mr. Maitland is a Chartered Professional Accountant with over 35 years of senior business experience, primarily in the oil and gas industry. He is also a director of Perpetual Energy Inc. He graduated from the University of Calgary in 1975 with a Bachelor of Commerce degree and obtained his C.A. designation in 1977. He was the VP, Finance and Chief Financial Officer of various private and publicly listed oil and gas companies from 1985 until he retired from active employment in 2007. Mr. Maitland completed his designation from the Institute of Corporate Directors (ICD.D) in 2006.

John Chambers, Director

Independent businessman since November 2018. Mr. Chambers was Vice Chairman, President at GMP FirstEnergy and a member of GMP Securities Executive Committee from 2016 to 2018. Prior thereto, he was the Chief Executive Officer at FirstEnergy Capital Corp. Mr. Chambers has over 25 years experience in Energy Capital Markets and M&A advisory and is a former chair of the Investment Industry Association of Canada. Mr. Chambers holds an ICD.D designation from the Institute of Corporate Directors, has an MBA in International Finance from McGill University and a BSc in Geophysics from the University of British Columbia.

Corporate Cease Trade Orders or Bankruptcies

To the knowledge of management of the Corporation, other than as set forth below, there has been no director or officer, or any shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, that is, or within the 10 years before the date of this Annual Information Form has been, a director or officer of any other issuer that:

(a) while that person was acting in that capacity, was the subject of a cease trade or similar order, or an order that denied the other issuer access to any exemptions under Canadian securities legislation, for a period of more than 30 consecutive days; or

(b) while that person was acting in that capacity, was subject to an event that resulted, after the director or executive officer ceased to be a director or executive officer, in the other issuer being the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation, for a period of more than 30 consecutive days; or

(c) while that person was acting in that capacity or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

Mr. Maitland was a director of GasFrac Energy Services Inc. ("**GasFrac**") from April 2008 until GasFrac's annual meeting held on May 27, 2014 at which time he did not stand for re-election to the GasFrac board of directors. GasFrac obtained court approval on January 28, 2015 under the *Companies' Creditors Arrangement Act* (the "**CCAA**") in respect of a forbearance agreement between GasFrac and its major creditor until March 18, 2015. Substantially all assets were sold under a court ordered process approving the wind-up of GasFrac on March 16, 2015.

Mr. Gee was a director of Endurance Energy Ltd. ("**Endurance**"), a corporation engaged in the exploration and production of natural gas. Mr. Gee resigned as a director of Endurance on September 1, 2015. Nine months after Mr. Gee's resignation, Endurance filed for creditor protection under the CCAA on May 30, 2016.

Penalties or Sanctions

To the knowledge of management of the Corporation, no director or officer, or any shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, has:

(a) been subject to any penalties or sanctions imposed by a court relating to Canadian securities legislation or by a Canadian securities regulatory authority or has entered into a settlement agreement with the Canadian securities regulatory authority; or

(b) been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Personal Bankruptcies

To the knowledge of management of the Corporation, there has been no director or officer, or any shareholder holding sufficient number of securities of the Corporation to affect materially the control of the Corporation, or a personal holding company of any such person that has, within the 10 years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or was subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director or officer.

Conflicts of Interest

Circumstances may arise where members of the Board of Directors are directors or officers of corporations which are in competition to the interests of the Corporation. No assurances can be given that opportunities identified by such Board members in the context of their relationship with another corporation will be provided to the Corporation. Pursuant to the ABCA, directors who have an interest in a proposed transaction upon which the Board of Directors is voting are required to disclose their interests and refrain from voting on the transaction.

Legal Proceedings and Regulatory Actions

There are no legal proceedings that the Corporation is or was a party to, or that any of its property is or was the subject of, during the Corporation's most recent financial year, nor are any such legal proceedings known to the Corporation to be contemplated, that involves a claim for damages, exclusive of interest and costs, exceeding 10% of the current assets of the Corporation.

There are no: (i) penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority during the year ended December 31, 2020; (ii) other penalties or sanctions imposed by a court or regulatory body against the Corporation that it believes would likely be considered important to a reasonable investor in making an investment decision; or (iii) settlement agreements entered into by the Corporation with a court relating to securities legislation or with a securities regulatory authority during the financial year ended December 31, 2020.

Interest of Management and Others in Material Transactions

There is no material interest, direct or indirect, of any: (a) director or executive officer of the Corporation; (b) person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of any class or series of the Corporation's voting securities; or (c) associate or affiliate of any of the persons or companies referred to in (a) or (b) above in any transaction within the three most recently completed financial years before the date of this AIF or during the current financial year that has materially affected or is reasonably expected to materially affect the Corporation.

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of Reference

The mandate and responsibilities of the audit committee of the Board of Directors (the "Audit Committee") of the Corporation is attached hereto as Appendix "C".

Composition of the Audit Committee

The members of the Audit Committee, being Messrs. Robert Maitland, John McAleer and Darren Gee, are financially literate and are independent in accordance with National Instrument 52-110 – *Audit Committees*.

Relevant Education and Experience

The members of the Corporation's Audit Committee are Mr. Maitland, Mr. McAleer and Mr. Gee. Their backgrounds and qualifications which are relevant to their service on the Audit Committee are listed above.

Pre-Approval of Policies and Procedures

The Audit Committee shall review and pre-approve all non-audit services to be provided to Altura by its external auditors.

External Auditor Service Fees

The following table discloses fees billed to the Corporation for the last two fiscal years by the Corporation's independent auditors:

	Year ended December 31, 2020 ($)	**Year ended December 31, 2019** ($)
Audit fees(1)	130,225	126,000
Audit-related fees(2)	-	-
Tax fees(3)	7,000	6,688
All other fees	-	-
TOTAL	137,225	132,688

Notes:

(1) Audit fees include costs of professional services rendered by KPMG for the audit of the Corporation's annual financial statements, and the review of the Corporation's interim financial statements.

(2) Represents the aggregate fees incurred in each of the last two fiscal years by the Corporation for assurance and related services that are reasonably related to the performance of the audit or review of the Corporation's financial statements (and not reported under the heading "Audit Fees").

(3) Tax fees consist of fees in respect of services provided in connection with tax compliance relating to the Corporation's federal and provincial income tax returns, tax advice and tax planning.

Exemption

Because the Corporation's shares are listed on the TSXV, the Corporation is exempt from the requirements of Part 3 (Composition of the Audit Committee) and Part 5 (Reporting Obligations) of National Instrument 52-110 – *Audit Committees* and relies on the exemptions therein.

DIVIDENDS AND DISTRIBUTIONS

The Corporation has not declared nor paid any dividends on its Common Shares. Any decision to pay dividends on the Common Shares will be made by the Board of Directors on the basis of the Corporation's earnings, financial requirements and other conditions existing at such future time.

DESCRIPTION OF SHARE CAPITAL

The authorized capital of the Corporation consists of an unlimited number of Common Shares and an unlimited number of Preferred Shares, issuable in series. As at December 31, 2020 and as at April 28, 2021, an aggregate of 108,920,974 Common Shares were issued and outstanding and no Preferred Shares were issued or outstanding.

The following is a summary of the rights, privileges, restrictions and conditions that attach to the Common Shares and the Preferred Shares.

Common Shares

The Corporation is authorized to issue an unlimited number of Common Shares. Holders of Common Shares are entitled to one vote per share at meetings of holders of Common Shares, to receive dividends if, as and when declared by the Board of Directors and to receive pro rata the remaining property and assets of the Corporation upon its dissolution or winding up, subject to the rights of shares having priority over the Common Shares.

Preferred Shares

The Corporation is authorized to issue an unlimited number of Preferred Shares, issuable in series. Preferred Shares have priority over Common Shares in regards to dividends and return of capital and may also be given such other preference over the Common Shares as the Board may determine at the time of issuance.

Stock Options

As at December 31, 2020 the Corporation had outstanding a total of 6,085,000 Options to purchase Common Shares issued to its directors and officers exercisable at a weighted average price of $0.36 per Common Share with expiry dates ending March 27, 2024. As at the date hereof, the Corporation has outstanding a total of 6,085,000 Options. As at April 28, 2021, 5,193,338 Options have vested and are exercisable at an average price of $0.35 per Common Share.

MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSXV under the symbol "ATU". The following table sets forth the price range and trading volume of these securities as reported by the TSXV for the period January 1, 2020 to December 31, 2020.

Month	High ($)	Low ($)	Volume
January 2020	0.37	0.32	590,633
February 2020	0.345	0.22	683,100
March 2020	0.28	0.11	2,899,935
April 2020	0.24	0.14	2,553,766
May 2020	0.24	0.18	937,798
June 2020	0.20	0.145	1,483,117
July 2020	0.18	0.14	610,357
August 2020	0.175	0.15	422,480
September 2020	0.165	0.12	835,618
October 2020	0.13	0.115	750,534
November 2020	0.19	0.11	2,621,290
December 2020	0.15	0.12	1,457,450

During the financial year ended December 31, 2020, no Common Shares and no Options were issued.

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

The Corporation has no escrowed securities or securities subject to contractual restriction on transfer.

INDUSTRY CONDITIONS

Production and Operation Regulations

The oil and natural gas industry is subject to extensive controls, laws and regulations imposed by various levels of government. These laws and regulations may be changed in response to economic or political conditions, and regulate, among other things, land tenure and the exploration, development, production, handling, storage, transportation, and disposal of crude oil and natural gas, crude oil and natural gas by-products, and other substances and materials produced or used in connection with oil and gas operations. Although, it is not expected that any of these controls or regulations will affect the operations of Altura in a manner that is materially different than they would affect other oil and natural gas corporations of similar size, the controls and regulations should be considered carefully by investors. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in Western Canada.

Pricing and Marketing

Crude Oil

In Canada, the producers of crude oil are entitled to negotiate sales contracts directly with crude oil purchasers. As a result, macroeconomic and microeconomic market forces determine the price of crude oil. Crude oil prices are primarily based on worldwide supply and demand; however, regional market and transportation issues also influence prices. Specific prices depend in part on oil quality, prices of competing fuels, distance to market, access to downstream transportation, value of refined products, length of contract term, weather conditions, the balance of supply and demand and other contractual terms.

In 2020, worldwide oversupply of crude oil, a lack of available storage capacity and decreased demand due to COVID-19 had a significant impact on the pricing of crude oil. In an effort to stabilize global oil markets, the Organization of the Petroleum Exporting Countries ("**OPEC**") and a number of other oil producing countries announced an agreement to cut crude oil production by approximately 10 million bbl/d in April 2020, which has been amended and adjusted throughout 2020 and early 2021 and remains subject to additional modification and uncertainty.

Natural Gas

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

Natural Gas Liquids

The price of NGLs sold in intra-provincial, interprovincial and international trade is determined by negotiations between buyers and sellers. Such price depends, in part, on the quality of the NGLs, price of competing chemical stock, distance to market, access to downstream transportation, length of contract term, the demand/supply balance and other contractual terms.

Exports from Canada

On August 28, 2019, Bill C-69 came into force, replacing, among other things, the National Energy Board Act (the "**NEB Act**") with the Canadian Energy Regulator Act (the "**CERA**"), the Canadian Environmental Assessment Act, 2012 with the Impact Assessment Act (the "**IAA**") and replacing the National Energy Board (the "**NEB**") with the Canadian Energy Regulator ("**CER**"). The CER has assumed the NEB's responsibilities broadly, including with respect to the export of crude oil, natural gas and NGL from Canada. The legislative regime relating to exports of crude oil, natural gas and NGL from Canada has not changed substantively under the new regime.

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

Orders from the CER provide a short-term alternative to export licenses and may be issued more expediently, since they do not require a public hearing (in the case of crude oil) or approval from the cabinet of the Canadian federal government. Orders are issued pursuant to the Part VI Regulation for up to one or two years depending on the substance, with the exception of natural gas (other than NGLs) for which an order may be issued for up to twenty years for quantities not exceeding 30,000 m3 per day.

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

As discussed in more detail below, one major constraint to the export of crude oil, natural gas and NGLs outside of Canada is the deficit of overall pipeline and other transportation capacity to transport production from Western Canada to the United States and other international markets. Although certain pipeline and other transportation projects are underway, many contemplated projects have been cancelled or are delayed due to regulatory hurdles, court challenges and economic and other socio-political factors. The transportation capacity deficit is not likely to be resolved quickly. Major pipeline and other transportation infrastructure projects typically require a significant length of time to complete once all regulatory and other hurdles have been cleared. In addition, production of crude oil, natural gas and NGLs in Canada is expected to continue to increase, which may further exacerbate the transportation capacity deficit.

Transportation Constraints, Pipeline Capacity and Market Access

Producers negotiate with pipeline operators (or other transport providers) to transport their products to market on a firm or interruptible basis. Transportation availability is highly variable across different areas and regions. This variability can determine the nature of transportation commitments available, the number of potential customers that can be reached in a cost-effective manner and the price received. Due to growing production and a lack of new and expanded pipeline and rail infrastructure capacity, producers in Western Canada have experienced low commodity pricing relative to other markets in the last several years.

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

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

With respect to the current state of the transportation and exportation of crude oil from Western Canada to domestic and international markets, the Enbridge Line 3 Replacement from Hardisty, Alberta, to Superior, Wisconsin, formerly expected to be in-service in late 2019, continues to experience permitting difficulties in the United States and completion of the United States portion of the pipeline replacement has been delayed following the announcement that the Minnesota Pollution Control Agency will require a public hearing concerning a key water permit. It is now expected that most of the construction work on the United States portion of the pipeline replacement will happen in 2021. The Canadian portion of the replaced pipeline began commercial operation on December 1, 2019.

The proposed Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of sustained political opposition in British Columbia, the Federal government entered into an agreement with Kinder Morgan Cochin ULC in May 2018 to purchase the shares and units of the entities that own and operate the Trans Mountain Pipeline system. The shareholders subsequently voted to approve the transaction in August 2018. However, the Trans Mountain Pipeline expansion experienced a setback when, in August 2018, the Federal Court of Appeal identified deficiencies in the NEB's environmental assessment and the federal government's indigenous consultations. The Court quashed the accompanying certificate of public convenience and necessity and directed Cabinet to correct these deficiencies. Following a reconsideration by the NEB and enhanced consultation efforts led by the federal government, Cabinet reapproved the Trans Mountain Pipeline expansion. Subsequent challenges to the approval were rejected by the Federal Court of Appeal in February 2020 and the Supreme Court of Canada in July 2020.

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

Construction commenced on the Trans Mountain Pipeline expansion in late 2019 and it is expected to be in-service in late 2022.

TC Energy Corporation's ("**TC Energy**") Keystone XL Pipeline was expected to begin construction in the first half of 2019, but pre-construction work was halted in late 2018 when a U.S. Federal Court Judge determined the underlying environmental review was inadequate. The United States Department of State issued its final supplemental environmental impact statement in late 2019, and in January 2020, the United States Government announced its approval of a right-of-way that would allow the Keystone XL Pipeline to cross 74 kilometers of federal land. On March 31, 2020, TC Energy announced it would proceed with the Keystone XL Pipeline. TC Energy also announced that the Government of Alberta had made a US $1.1 billion equity investment in the project and would guarantee a US $4.2 billion project level credit facility.

While construction on the Keystone XL Pipeline started in April 2020, the Keystone XL Pipeline remained subject to legal and regulatory barriers in the United States. In December 2019, a federal judge in Montana rejected the United States Government's request to dismiss a lawsuit by Native American tribes attempting to block certain permits and on April 15, 2020, a Montana judge ruled against the U.S. Army Corps of Engineers' use of a national permit for water crossings in the United States (Nationwide Permit 12). The United States Court of Appeals for the Ninth Circuit refused to stay the ruling. While the Supreme Court of the United States subsequently reinstated Nationwide Permit 12 in July 2020, it determined that the reinstatement would not apply to the Keystone XL Pipeline.

On January 20, 2021, Mr. Joseph Biden was sworn in as the 46th President of the United States, following which the Biden administration announced its decision to revoke the federal permit granted by the previous administration for the Keystone XL Pipeline, which has overturned a comprehensive regulatory process that lasted more than a decade. As a result of the revocation, TC Energy has indicated that they have suspended advancement of the Keystone XL Pipeline project while it reviews the decision, assesses the implications of the decision and considers its options.

Bill C-48, the Oil Tanker Moratorium Act (the "**OTMA**"), came into force on June 21, 2019. The OTMA imposes a moratorium on tanker traffic transporting certain crude oil and NGL products from British Columbia's north coast. The OTMA is subject to a review after five years.

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

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

Several shippers challenged Enbridge's open season and, in particular, Enbridge's ability to engage in an open season without prior regulatory approval. Following an expedited hearing process, the CER decided to shut down the open season, citing concerns about fairness and uncertainty regarding the ultimate terms and conditions of service. On December 19, 2019, Enbridge applied to the CER for a hearing for the right to hold an open season.

Natural gas prices in Alberta and British Columbia have also been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. While companies that secure firm access to transport their natural gas production out of Western Canada may be able to access more markets and obtain better pricing, other companies may be forced to accept spot pricing in Western Canada for their natural gas, which in the last several years has generally been depressed (at times producers have received negative pricing for their natural gas production).

Required repairs or upgrades to existing pipeline systems have also led to further capacity constraints and apportionment of firm access, which in Western Canada may be further exacerbated by natural gas storage limitations. However, in September 2019, the CER approved a policy change by TC Energy on its NOVA Gas Transmission Ltd. pipeline network ("**NGTL System**"), which carries much of Alberta's natural gas production, to give priority to deliveries into storage. The change has served to somewhat stabilize supply and pricing, particularly during periods of maintenance on the system. An expansion to the NGTL System was recommended for approval by the CER and is currently waiting to receive federal Cabinet approval and the CER has started a process to determine whether it will extend the temporary service protocol.

Additionally, while a number of liquefied natural gas export plants have been proposed for the west coast of Canada, government decision-making, regulatory uncertainty, opposition from environmental and indigenous groups, and changing market conditions, have resulted in the cancellation or delay of many of these projects. In October 2018, the proponents of the LNG Canada liquefied natural gas export terminal announced a positive final investment decision to proceed with the project. Pre-construction activities began in November 2018, with a planned completion target of 2025.

The Cedar LNG Project near Kitimat by Cedar LNG Export Development Ltd. is currently in the environmental assessment stage, with British Columbia’s Environmental Assessment Office conducting the environmental assessment on behalf of the Impact Assessment Agency of Canada ("**IA Agency**").

In December 2019, the CER approved a 40-year export licence for the Kitimat LNG project, a proposed joint venture between Chevron Canada Limited and Woodside Energy International (Canada) Limited, a subsidiary of Woodside Petroleum Ltd. However, both partners are looking to sell some or all of their interest in the project.

The Woodfibre LNG Project is a small-scale LNG processing and export facility near Squamish, British Columbia. The BC Oil and Gas Commission approved a project permit for Woodfibre LNG, a subsidiary of Singapore-based Pacific Oil and Gas Ltd. in July 2019. Pacific Oil and Gas Ltd. is expected to formally approve the project in the third quarter of 2021, with construction beginning shortly thereafter.

GNL Québec Inc., the proponent of the Énergie Saguenay Project, is currently working its way through a federal impact assessment process for the construction and operation of an LNG facility and export terminal located on Saguenay Fjord, an inlet which feeds into the St. Lawrence River. The Énergie Saguenay Project is currently slated for completion in 2026.

The Goldboro LNG project, located in Nova Scotia, proposed by Pieridae Energy Ltd. ("**Pieridae**"), would see LNG exported from Canada to European markets. Pieridae has agreements with Shell, upstream, and with Uniper, a German utility, downstream. The federal government has issued Goldboro LNG a 20-year export licence, but Pieridae has delayed its final investment decision until mid-2021.

Curtailment

On December 2, 2018, the Government of Alberta announced that, commencing January 1, 2019, it would mandate a short-term reduction in provincial crude oil and crude bitumen production. As contemplated in the Curtailment Rules, as amended effective October 1, 2019 the Government of Alberta, on a monthly basis, subjects crude oil producers producing more than 20,000 bbl/d to curtailment orders that limit their production according to a pre-determined formula that allocates production limits proportionately amongst all operators subject to curtailment orders.

Where an operator to whom a curtailment order applies is a joint venture or partnership, the partners or joint venturers may enter into an agreement respecting the allocation of the combined production among themselves to comply with the curtailment order.

Curtailment first took effect on January 1, 2019, limiting province-wide production of crude oil and crude bitumen to 3.56 million bbl/d. The curtailment rate dropped gradually over the course of 2019 and was set at 3.81 million bbl/d through 2020. As of January 2021, monthly oil production limits are no longer in effect. However, the Curtailment Rules, which were set to be repealed on December 31, 2020, have been extended so that the Government of Alberta retains the ability to impose production limits if needed.

NAFTA/USMCA and Other Trade Agreement

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

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

Canada has also pursued a number of other international free trade agreements with other countries around the world and, as a result, a number of free trade or similar agreements are in force between Canada and certain other countries. Canada and the European Union recently agreed to the Comprehensive Economic and Trade Agreement ("**CETA**"), which provides for duty-free, quota-free market access for Canadian oil and gas products to the European Union. Although CETA remains subject to ratification by certain national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017. In light of the United Kingdom's departure from the European Union (Brexit) on January 31, 2020, the United Kingdom and Canada have reached an interim post-Brexit trade agreement, the Canada-United Kingdom Trade Continuity Agreement ("**CUKTCA**"). On December 9, 2020, the Government of Canada introduced Bill C-18, an Act to Implement the Trade Continuity Agreement. CETA ceased to apply to Canada-United Kingdom trade on January 1, 2021. The CUKTCA replicates CETA on a bilateral basis and is meant to maintain the status quo of the Canada-United Kingdom trade relationship.

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

While it is uncertain what effect CETA, CPTPP, CUKTCA or any other trade agreements will have on the oil and 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 oil and gas producers to benefit from such trade agreements.

Extractive Sector Transparency Measures Act

On June 1, 2015, the federal *Extractive Sector Transparency Measures Act* ("**ESTMA**") came into effect. This federal legislation imposes mandatory reporting requirements on certain entities engaged in the "commercial development of oil, gas or minerals", which includes exploration, extraction and holding permits to do so. All companies subject to ESTMA are required to report payments over $100,000 made to any level of a Canadian or foreign government, including royalty payments, taxes (other than consumption taxes and personal income taxes), fees, production entitlements, bonuses, dividends (other than ordinary dividends paid to shareholders), infrastructure improvement payments and other prescribed categories of payments. These categories are separate; therefore, even if the aggregate of payments across the categories are greater than $100,000, one or more individual categories must reach the threshold for the report to be required. Any persons or entities found in violation of ESTMA (which includes making a false report, failing to make the report public or failing to maintain records for the prescribed period) can be fined up to $250,000 for each day that the offence continues.

Land Tenure

Where mineral rights are owned by the government, rights are granted to energy companies to explore for and produce crude oil, bitumen and natural gas pursuant to leases, licenses, permits and regulations as legislated by the respective provincial and federal governments. Crown lease terms vary in length, usually from two to five years for oil and natural gas leases and usually 15 years for Alberta bitumen leases. Other terms and conditions to maintain a mineral lease are set forth in the relevant legislation or are negotiated.

Lands subject to a Crown oil and natural gas lease are continued beyond their primary term by drilling a well. A lease is proven productive at the end of its primary term by drilling, producing, mapping, being part of a unit agreement or by paying offset compensation. If a lease is proven productive, it will continue indefinitely beyond the initial term of the lease. The tenure only comes to an end when the holder can no longer prove the lands subject to the lease are capable of producing crude oil or natural gas.

Many jurisdictions in Canada, including the provinces of Alberta and Saskatchewan have legislation in place for mineral rights reversion to the Crown where stratigraphic formations cannot be shown to be capable of production at the end of their primary lease term. Such legislation may also include mechanisms available to energy companies to "continue" lease terms for nonproducing lands, having met certain criteria as laid out in the relevant legislation.

Crude oil and natural gas can also be privately owned (freehold) and rights to explore for and produce such crude oil and natural gas are granted by leases on such terms and conditions as may be negotiated between the landowner and the lessee.

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

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner’s interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the Western Canadian provinces have established incentive programs for exploration and development. Such programs often provide for royalty reductions, credits and holidays, and are generally introduced when commodity prices are low to encourage exploration and development activity. Additional programs may be introduced to encourage producers to undertake initiatives using new technologies that may enhance or improve recovery of crude oil, natural gas and NGLs or improve environmental performance.

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

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

Alberta

In terms of crude oil or natural gas production from Crown lands, royalties are payable to the Province of Alberta. In respect of freehold lands, royalties are payable to the mineral owner and taxes are payable to the Province of Alberta. The Government of Alberta's approach to the royalty and tax regime is regularly reviewed for compliance with the purpose of the regimes; to ensure that Albertans are receiving a fair share from energy development through royalties, taxes and fees.

On January 29, 2016, the Government of Alberta released and accepted the Royalty Review Advisory Panel's recommendations, which outlined the implementation of Modernized Royalty Framework for Alberta ("**MRF**"). The MRF formally took effect on January 1, 2017 for new wells drilled after this date. The previous royalty framework (the "**Old Framework**") will continue to apply to wells drilled prior to January 1, 2017 for a period of ten years ending on December 31, 2026. After the expiry of this ten-year period, these older wells will become subject to the Modernized Framework. On July 12, 2016, the Government of Alberta announced that producers could apply for early adoption of the MRF in respect of wells spud between July 13, 2016 and December 31, 2016. As of January 1, 2027, these older wells will become subject to the Modernized Framework. The Royalty Guarantee Act (Alberta), which came into effect on July 18, 2019, provides that no major changes will be made to the current crude oil and natural gas royalty structure for a period of at least 10 years.

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

Producers pay a flat royalty rate of 5% of gross revenue from each well that is subject to the MRF until the well reaches payout. Payout for a well is the point at which cumulative gross revenues from the well equals the Drilling and Completion Cost Allowance for the well set by the AER. After payout, producers pay an increased post-payout royalty on revenues determined by reference to the then current commodity prices of the various hydrocarbons. Similar to the Old Framework, the post-payout royalty rate under the MRF varies with commodity prices. Once production in a mature well drops below a threshold level where the rate of production is too low to sustain the full royalty burden, its royalty rate is adjusted downward as the mature well's production declines.

As the MRF uses deemed drilling and completion costs in calculating the royalty and not the actual drilling and completion costs incurred by a producer, low cost producers benefit if their well costs are lower than the Drilling and Completion Cost Allowance and, accordingly, they continue to pay the lower 5% royalty rate for a period of time after their wells achieve actual payout.

The Old Framework is applicable to all conventional crude oil and natural gas wells drilled prior to January 1, 2017 and bitumen production. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for conventional crude oil production under the Old Framework range from a base rate of 0% to a cap of 40%. The Old Framework also includes a natural gas royalty formula which provides for a reduction based on the measured depth of the well below 2,000 metres deep, as well as the acid gas content of the produced gas. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for natural gas production under the Old Framework range from a base rate of 5% to a cap of 36%. Under the Old Framework, the royalty rate applicable to natural gas liquids is a flat rate of 40% for pentanes and 30% for butanes and propane.

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

Freehold and Other Types of Non-Crown Royalties

Royalties on production from privately-owned freehold lands are negotiated between the mineral freehold owner and the lessee under a negotiated lease or other contract. Producers and working interest participants may also pay additional royalties to parties other than the mineral freehold owner where such royalties are negotiated through private transactions. In addition to the royalties payable to the mineral owners (or to other royalty holders if applicable), producers of crude oil and natural gas from freehold lands in each of the Western Canadian provinces are required to pay freehold mineral taxes or production taxes. Freehold mineral taxes or production taxes are taxes levied by a provincial government on crude oil and natural gas production from lands where the Crown does not hold the mineral rights.

The government agency IOGC is responsible for the management of crude oil and natural gas resources located on indigenous reservations across Canada. IOGC's responsibilities include negotiating and issuing the crude oil and natural gas agreements between indigenous groups and crude oil and natural gas companies, as well as collecting royalty revenues on behalf of indigenous groups and depositing the revenues in their trust accounts. While certain standards exist, the exact terms and conditions of each crude oil and natural gas lease dictate the calculation of royalties owed, which may vary depending on the involvement of the specific indigenous group. Ultimately, the relevant indigenous group must approve the terms.

Regulatory Authorities and Environmental Regulation

The Canadian oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the 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 legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability and the imposition of material fines and penalties. In addition to these specific known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and greenhouse gas ("**GHG**") emissions, may impose further requirements on operators and other companies in the oil and natural gas industry.

Altura has established internal guidelines to be followed to comply with environmental laws and regulations in the jurisdictions in which the Corporation operates. The Corporation employs an environmental, health, and safety consultant whose responsibilities include providing assurance that Altura's operations are carried out in accordance with applicable environmental guidelines and safety precautions. Although the Corporation maintains pollution insurance against the costs of cleanup operations, public liability, and physical damage, there is no assurance that such insurance will be adequate to cover all such costs or that such insurance will continue to be available in the future.

Federal

Canadian environmental regulation is the responsibility of the federal government and provincial governments. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law will prevail, however, such conflicts are uncommon. The federal government has primary jurisdiction over federal works, undertakings and federally regulated industries such as railways, aviation and interprovincial transport including interprovincial pipelines. The Canadian Environmental Protection Act, 1999 and the Canadian Environmental Assessment Act, 2012 provide the foundation for the federal government to protect the environment and cooperate with provinces to do the same.

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

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

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

The federal government has stated that an objective of the legislative changes was to improve decision certainty and turnaround times. Once a review or assessment is commenced under either the CERA or IAA, there are limits on the amount of time the relevant regulatory authority will have to issue its report and recommendation. Designated projects will go through a planning phase to determine the scope of the impact assessment, which the federal government has stated should provide more certainty as to the length of the full review process. Applications for non-designated projects will follow a similar process as under the NEB Act. There is significant uncertainty surrounding the impact of Bill C-69 on oil and natural gas projects. There was significant opposition from industry and others in respect of Bill C-69, and notwithstanding its stated purpose, there is concern that the changes brought about by Bill C-69 will result in projects not being approved or increased delays in approvals. The Government of Alberta has submitted a reference question to the Alberta Court of Appeal regarding the constitutionality of the IAA and the hearing is expected to take place in the first half of 2021.

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

Alberta

The discharge of crude oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge in the event that they are not covered by Altura's insurance. Although the Corporation maintains insurance to industry standards, which in part covers liabilities associated with discharges, it is not certain that such insurance will cover all possible environmental events, foreseeable or otherwise, or whether changing regulatory requirements or emerging jurisprudence may render such insurance of little benefit. In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and GHG emissions, may impose further requirements on operators and other companies in the oil and natural gas industry.

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

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

The Government of Alberta's land-use policy for surface land in Alberta sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of seven region-specific land-use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effect management approach into such plans. As a result, several regional plans have been implemented and others are in the process of being implemented. These regional plans may affect further development and operations in such regions.

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

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

Liability Management Rating Programs

Alberta

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

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

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

As a result of the Supreme Court of Canada's decision in Orphan Well Association v Grant Thornton (also known as the Redwater decision), receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets of a bankrupt licensee that have reached the end of their productive lives and represent a liability while dealing with the company's valuable assets for the benefit of the company's creditors without first satisfying abandonment and reclamation obligations. In April 2020, the Government of Alberta passed Bill 12: The Liabilities Management Statutes Amendment Act. Bill 12 places the burden of a defunct licensees' 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. Bill 12 will come into force on proclamation.

In response to the increase in orphaned crude oil and natural gas sites and the environmental risks associated therewith, the AER issued several bulletins and interim rule changes to govern the AER's administration of its licensing and liability management programs. The AER amended its Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals, which deals with licence eligibility to operate wells and facilities, to require the provision of extensive corporate governance and shareholder information, including whether any director and officer was a director or officer of an energy company that has been subject to insolvency proceedings in the last five years. All transfers of well, facility and pipeline licences in the province are subject to AER approval. As a condition of transferring existing AER licences, approvals and permits, all transfers are now assessed on a non-routine basis and the AER now requires all transferees to demonstrate that they have an LMR of 2.0 or higher immediately following the transfer, or to otherwise prove to the satisfaction of the AER that it can meet its abandonment and reclamation obligations.

Both the Government of Alberta and/or the AER may make further rule changes to Alberta's liability management programs at any time. For example, on July 30, 2020, the Government of Alberta announced a new Liability Management Framework ("**AB LMF**") that will replace the AB LLR Program and its constituent programs. Among other changes under the AB LMF, the AB LLR Program will be replaced with the Licensee Capability Assessment System, which is intended to be a more comprehensive assessment of corporate health and will consider a wider variety of factors than those considered under the AB LLR Program and will establish clear expectations for industry with regards to the management of liabilities throughout the entire lifecycle of crude oil and natural gas projects. Importantly, the AB LMF will also provide proactive support to distressed operators and will require companies operating in Alberta's petroleum and natural gas industry to make mandatory annual minimum payments towards outstanding reclamation obligations in accordance with five year rolling spending targets. It is not yet clear how or when then AB LMF will be implemented.

The AER has also implemented the Inactive Well Compliance Program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under Directive 013: Suspension Requirements for Wells ("**Directive 013**"). The IWCP applies to all inactive wells that are noncompliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within five years. As of April 1, 2015, each licensee is required to bring 20% of its inactive wells into compliance every year, either by reactivating or by suspending the wells in accordance with Directive 013 or by abandoning them in accordance with Directive 020: Well Abandonment.

As part of its strategy to encourage the decommissioning, remediation and reclamation of inactive or marginal crude oil and natural gas infrastructure, the AER announced a voluntary area-based closure (ABC) program in 2018. The ABC program is designed to reduce the cost of abandonment and reclamation operations though industry collaboration and economies of scale. Participants seeking to participate in the program must commit to an inactive liability reduction target to be met through closure work of inactive assets.

Federal and Provincial Support for Liability Management

As part of an announcement of federal relief for Canada's petroleum and natural gas industry in response to COVID-19, the federal government pledged $1.72 billion to clean up orphan and inactive wells in Alberta, Saskatchewan and British Columbia. However, these funds are being administered by regulatory authorities in each province. In Alberta, the Ministry of Energy is disbursing its $1 billion share of the federally provided funds through the Site Rehabilitation Program. The Government of British Columbia is disbursing its $120 million share of the federally provided funds through three programs: the Dormant Sites Reclamation Program, the Orphan Sites Supplemental Reclamation Program and the Legacy Sites Reclamation Program. In addition to the funds administered by the respective provincial governments, the federal government announced a $200 million loan to Alberta's Orphan Fund. And in early March 2020, the Government of Alberta announced an extension by up to $100 million of an existing $235 million loan to the Orphan Fund. In Saskatchewan, $400 million in federal funding will be allocated through the Accelerated Site Closure Program ("**ASCP**"). The first phase of the ASCP will make $100 million available to eligible service companies to conduct abandonment and reclamation work. Further tranches of the ASCP, up to $300 million, will be made available in the future.

Climate Change Regulation

Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulation of the crude oil and natural gas industry in Canada. In general, there is some uncertainty with regard to the impacts of federal or provincial climate change and environmental laws and regulations, as it is currently not possible to predict the extent of future requirements. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact on the Corporation's operations and cash flow.

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") since 1992. Since its inception, the UNFCCC has instigated numerous policy experiments with respect to climate governance. On April 22, 2016, 197 countries, including Canada, signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. To date, 189 of the 197 parties to the convention have ratified the Paris Agreement, including Canada. In December 2019, the United Nations annual Conference of the Parties took place in Madrid, Spain. The Conference concluded with the attendees delaying decisions about a prospective carbon market and emissions cuts until the next climate conference, scheduled to take place in November 2021.

The Government of Canada has pledged to cut its emissions by 40% from 2005 levels by 2030, but indicated in the recent Speech from the Throne (also referred to as the Throne Speech) that it may implement policy changes to exceed this target. Specific details have not yet been announced. In connection with this target, the Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change in 2016, setting out a plan to meet the federal government's 2030 emissions reduction targets.

On December 11, 2020, the Government of Canada released its Healthy Environment and a Healthy Economy Plan (the “**HEHE Plan**”) which builds on the Pan-Canadian Framework and provides a road map forward to meet Canada's 2030 emissions reduction target. The HEHE Plan includes a $3-billion investment over five years to a Net-Zero Accelerator Fund to invest in projects to decarbonize large emitters, scale-up clean technology and otherwise accelerate industry transformation across all sectors. In addition, the HEHE Plan proposes to invest an additional $964 million over four years towards renewable energy and grid modernization projects and $300 million over five years to advance the use of clean and reliable energy in rural, remote and Indigenous communities. The third component of the HEHE Plan pertains to zero emission vehicles. This includes investing an additional $287 million to continue the federal government's Incentives for Zero-Emission Vehicles program until March 2022, $150 million over three years towards charging and refueling stations across Canada, and $1.5 billion towards a Low-Carbon and Zero-Emissions Fuels Fund to increase the production of low-carbon fuels. Also of relevance to the petroleum and natural gas industry, the federal government has announced that it will implement a ban on certain single-use plastics in 2021.

On November 19, 2020, the federal government announced Bill C-12, an Act respecting transparency and accountability in Canada's efforts to achieve net-zero greenhouse gas emissions by the year 2050. Canada joins over 120 countries in committing to net-zero emissions by 2050, including the UK, Germany, France and Japan. Once passed, Bill C-12 will legally bind the federal government to a process to achieve net-zero emissions by 2050. The legislation will, among other things, set rolling five-year emissions-reduction targets (starting in 2030) and require plans to reach each target on a reporting basis and enshrine greater accountability and public transparency into Canada's plan for meeting net-zero emissions by 2050 by providing for independent third-party review by the Commissioner of the Environment and Sustainable Development.

On June 21, 2018, the federal government enacted the Greenhouse Gas Pollution Pricing Act (the "**GGPPA**"), which came into force on January 1, 2019. This regime has two parts: an output-based pricing system for large industry and a regulatory fuel charge imposing an initial price of $20/tonne of CO2e emissions. This system applies in provinces and territories that request it and in those that do not have their own emissions pricing systems in place that meet the federal standards. The effect of the GGPPA is that, regardless of whether a particular province has enacted legislation of its own, there is a uniform price on emissions across the country. Under current federal plans, this price will escalate by $10 per year until it reaches a price of $50/tonne of CO2e in 2022. Starting April 1, 2021, the minimum price permissible under the GGPPA is $40/tonne of CO2e.

Alberta, Saskatchewan, Ontario and Manitoba challenged the constitutionality of the GGPPA. In both the Saskatchewan and Ontario references, the appellate Courts ruled in favour of the constitutionality of the GGPPA; the Alberta Court of Appeal determined that the GGPPA is unconstitutional. All three judgments were appealed to the Supreme Court of Canada ("SCC") and the hearing took place in September 2020. In a decision released March 25, 2021, the SCC ruled that the GGPPA is constitutional.

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

As part of its efforts to provide relief to Canada's petroleum and natural gas industry in light of the COVID19 pandemic, on October 29, 2020, the federal government launched the $750-million Emission Reduction Fund to reduce methane and GHG emissions. The fund will provide repayable funding to eligible onshore and offshore crude oil and natural gas companies to support investments to reduce GHG emissions by adopting greener technologies.

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

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

The federal government has also announced that it will proceed with the development and implementation of a Clean Fuel Standard (CFS) that will require producers, importers and distributors to reduce the emissions intensity of gaseous, liquid and solid fuels. On December 18, 2020, the federal government published proposed CFS regulations, the final regulations of which are expected to be published in 2021 with the CFS regulations scheduled to come into force in 2022. The proposed CFS regulations take a performance-based approach to reducing greenhouse gas emissions. The CFS regulations require suppliers of liquid fuels, such as gasoline, diesel and kerosene to gradually cut the amount of carbon in their product. It is the goal of the program to incentivize innovation and adoption of clean technologies while giving fuel suppliers the ability to meet requirements in a cost-effective way that works for their business. The proposed regulations offer compliance credits to incentive industries to innovate and adopt cleaner technologies to lower their compliance costs.

Alberta

On November 22, 2015, the Government of Alberta introduced its Climate Leadership Plan (the "**CLP**"). Under this strategy, the Climate Leadership Act (the "**CLA**") came into force on January 1, 2017 and established a fuel charge intended to first outstrip and subsequently keep pace with the federal price. On December 14, 2016, the Oil Sands Emissions Limit Act came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, excluding some attributable to upgraders, the electric energy portion of cogeneration and other prescribed emissions. In June 2019, the Government of

Alberta pivoted in its implementation of the CLP and repealed the CLA. The Carbon Competitiveness Incentives Regime (CCIR) remained in place. As a result, the federally imposed fuel charge took effect in Alberta on January 1, 2020, at a rate of $20/tonne. In accordance with the GGPPA, this increased to $30/tonne on April 1, 2020 and increased to $40/tonne on April 1, 2021. However, on December 4, 2019, the federal government approved Alberta's proposed Technology Innovation and Emissions Reduction (TIER) regulation intended to replace the CCIR, so the regulation of emissions from heavy industry remains subject to provincial regulation, while the federal fuel charge still applies. The TIER regulation came into effect on January 1, 2020.

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

The Government of Alberta also signaled its intention through its CLP to implement regulations that would lower annual methane emissions by 45% by 2025. Pursuant to this goal, the Government of Alberta enacted the Methane Emission Reduction Regulation (the Alberta Methane Regulations) on January 1, 2020, and the AER simultaneously released an updated edition of Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting. The release of Directive 060 complements a previously released update to Directive 017: Measurement Requirements for Oil and Gas Operations that took effect in December 2018. Together, these new Directives represent Alberta's first step toward achieving its 2025 goal, as outlined in the Alberta Methane Regulations. In May 2020, the Government of Canada and the Government of Alberta announced a preliminary equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply once the agreement is effective.

Alberta was also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed $1.24 billion through 2025 to fund two commercial-scale carbon capture and storage projects that will begin commercializing the technology on the scale needed to be successful. Both projects will help reduce the CO2 emissions from the oil sands and fertilizer sectors and reduce GHG emissions by 2.76 million megatonnes per year. On December 2, 2010, the Government of Alberta passed the Carbon Capture and Storage Statutes Amendment Act, 2010, which deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions. This legislation is intended to encourage new carbon capture and storage projects in Alberta.

RISK FACTORS

The following are certain risk factors relating to the business of Altura which prospective investors should carefully consider before deciding whether to purchase shares. The following information is a summary only of certain risk factors and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this AIF. 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 Altura's business, the business of third parties with whom the Corporation conducts business and the crude oil and natural gas business generally.

Exploration, Development and Production Risks

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 Corporation's long-term commercial success depends on its ability to find, acquire, develop and commercially produce crude 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 reserves will depend on both the Corporation's ability to explore and develop existing properties and on the Corporation's ability to select and acquire suitable producing properties or prospects. There is no assurance that Altura will be able continue to find satisfactory properties to acquire or participate in. Moreover, management may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participation uneconomic. There is also no assurance that the Corporation will discover or acquire further commercial quantities of crude oil and natural gas.

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

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

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including but not limited to hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills and other environmental hazards, each of which could result in substantial damage to crude oil and natural gas wells, production facilities, other property and the environment or in personal injury.

Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including geological and seismic risks, 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 could have a material adverse effect on future results of operations, liquidity and financial condition.

As is standard industry practice, the Corporation is not fully insured against all risks, nor are all risks insurable. Although Altura 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. In either event, the Corporation could incur significant costs.

Weakness in the Oil and Gas Industry

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

Lower commodity prices may also affect the volume and value of the Corporation's reserves, especially as certain reserves become uneconomic. In addition, lower commodity prices have reduced, and are anticipated to continue to reduce, the Corporation's cash flow which could result in a reduced capital expenditure budget. As a result, the Corporation may not be able to replace its production with additional reserves and both the Corporation's production and reserves could be reduced on a year over year basis. A prolonged period of adverse market conditions may impede the Corporation's ability to refinance its Credit Facility or arrange alternative financing when the Credit Facility becomes due or if the lending limits under the Credit Facility are reduced upon periodic review (see "Risk Factors – Credit Facility Arrangements"). Given the current market conditions and the lack of confidence in the Canadian oil and gas industry, the Corporation may have difficulty raising additional funds in the future or if it is able to do so, it may be on unfavourable and highly dilutive terms. If these conditions persist, Altura's cash flow may not be sufficient to continue to fund operations and to satisfy obligations when due and will require additional equity or debt financing and/or proceeds from asset sales. There can be no assurance that such equity or debt financing will be available on terms that are satisfactory or at all. Similarly, there can be no assurance that the Corporation will be able to realize any or sufficient proceeds from asset sales to discharge its obligations.

Commodity Prices, Markets and Marketing

The marketability and price of crude oil and natural gas that may be acquired, discovered or produced by Altura is, and will continue to be, affected by numerous factors beyond its control. The Corporation's ability to market its crude oil and natural gas may depend upon its ability to acquire space on pipelines that deliver crude oil and natural gas to commercial markets or contract for the delivery of crude oil by rail. (see "*Industry Conditions – Transportation Constraints, Pipeline Capacity and Market Access" and "Risk Factors" - Weakness in the Oil and Natural Gas Industry*"). The Corporation may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines, railway lines processing and storage facilities; and operational problems affecting such pipelines, railway lines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of crude oil and natural gas and many other aspects of the oil and natural gas business.

The prices of crude oil and natural gas are expected to remain volatile for the near future because of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, shale oil production in the United States, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries, conflicts in the Middle East and ongoing credit and liquidity concerns. Prices for crude oil and natural gas are also subject to the availability of foreign markets and the ability to access such markets. Any material decline in prices or a continued low crude oil and natural gas price environment could result in a reduction of Altura's anticipated net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of crude oil or natural gas and a reduction in the volumes of the Company's reserves. Altura might also elect not to produce from certain wells at lower prices.

Volatile crude oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for crude oil and natural gas producing properties, as buyers, sellers, lessors and lessees have difficulty agreeing on the value or terms of such arrangements. Price volatility also makes it difficult to budget for and project the return on potential acquisitions, divestitures or leasing opportunities. See "*Weakness in the Oil and Natural Gas Industry*".

All of these factors could result in a material decrease in Altura's expected net production revenue and a reduction in its future crude oil and natural gas acquisition, exploration, development and production activities. Any substantial and extended decline in or continued low crude oil and natural gas prices would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business and financial condition.

In addition, bank borrowings available to Altura are determined by its borrowing base. A sustained material decline in prices from historical average prices could reduce Altura's borrowing base, therefore reducing the bank credit available which could require that a portion, or all, of Altura's bank debt be repaid.

Title to and Right to Produce from Assets

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

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

Volatility of Market Price of Common Shares

The trading price of securities of crude oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. The volatility may affect the ability of holders to sell the Common Shares at an advantageous price. Factors unrelated to the Corporation's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices and/or current perceptions of the crude oil and natural gas market. This includes, but is not limited to, changing and in some cases, negative investor sentiment towards energy-related businesses. In recent years, the volatility of commodities has increased due to, in part, the implementation of computerized trading and the decrease of discretionary commodity trading. In addition, the volatility, trading volume and share price of issuers have been impacted by increasing investment levels in passive funds that track major indices, as such funds only purchase securities included in such indices. In addition, in certain jurisdictions, institutions, including government sponsored entities, have determined to decrease their ownership in crude 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 may be due to Altura's operating results failing to meet the expectations of securities analysts or investors in any quarter, downward revision in securities analysts' estimates, governmental regulatory action, adverse change in general market conditions or economic trends, acquisitions, dispositions or other material public announcements by Altura or its competitors, along with a variety of additional factors, including, without limitation, those set forth under "Forward-Looking Statements". In addition, in recent years the market price for securities in the stock markets, including the TSX Venture Exchange, experienced significant price and trading fluctuations. These fluctuations have resulted in volatility in the market prices of securities that often has been unrelated or disproportionate to changes in operating performance. These broad market fluctuations may adversely affect the market prices of the Common Shares. Accordingly, the price at which the Common Shares will trade cannot be accurately predicted.

Regulatory Approvals

In order to conduct its crude oil and natural gas operations, the Corporation requires regulatory approvals from various government authorities. There can be no assurance that Altura will be able to obtain or renew all of the regulatory approvals that may be required to conduct operations that it may wish to undertake or that it will obtain such equipment and terms and conditions acceptable to Altura.

Operating and Capital Costs

The Corporation's financial performance is significantly affected by the cost of operating and the capital costs associated with its assets. Operating and capital costs are affected by a number of factors including, but not limited to inflationary price pressure, scheduling delays, failure to maintain quality standards and supply chain disruptions. Electricity, chemicals, supplies, abandonment, reclamation and labour costs are examples of operating costs that are susceptible to significant fluctuations. Fluctuations in operating and capital costs could negatively impact Altura's business, financial condition, results of operations, cash flows and value of its crude oil and natural gas reserves.

Hydraulic fracturing

Altura utilizes horizontal drilling, multi-stage hydraulic fracturing, specially formulated completion fluids and other technologies in connection with its drilling and completion activities. Public concern over the hydraulic fracturing process has raised questions regarding the completion fluids used in the fracturing process, their effect on fresh water aquifers and surface waterbodies, the use and disposal of water in connection with completion operations and the ability of such water to be recycled. Certain government and regulatory agencies in Canada and the United States have been investigating the potential risks associated with the hydraulic fracturing process. Altura is unable to predict the impact of any potential regulations upon the oil and gas industry and the impact to Altura's business. The implementation of new regulations with respect to water usage or hydraulic fracturing generally could increase Altura's costs of compliance, operating costs, the risk of litigation and environmental liabilities or negatively impact Altura's prospects, any of which may have a material adverse effect on our future business, financial condition and results of operations.

Due to seismic activity reported in the Fox Creek area of Alberta, the AER announced in February 2015, seismic monitoring and reporting requirements for hydraulic fracturing operators in the Duvernay zone in the Fox Creek area. These requirements include, among others, an assessment of the potential for seismicity prior to conducting operations, the implementation of a response plan to address potential seismic events, and the suspension of operations if a seismic event above a particular threshold occurs. These requirements will remain in effect as long as the AER deems them necessary. Further, the AER continues to monitor seismic activity around the province and may extend these requirements to other areas of the province if necessary.

Disposal of Fluids Used in Operations

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

Legal Proceedings

Altura may from time to time be subject to litigation and regulatory proceedings arising in the normal course of its business. Altura cannot determine whether such litigation and regulatory proceedings will, individually or collectively, have a material adverse effect on its business, results or operations and financial condition. To the extent expenses incurred in connection with litigation or any potential regulatory proceeding or action (which may include substantial fees of attorneys and other professional advisors and potential obligations to indemnify officers and directors who may be parties to such actions) are not covered by available insurance, such expenses could adversely affect Altura's cash position.

Third Party Credit Risk

The Corporation is or 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 financial instruments and other parties. In the event that such entities fail to meet their contractual obligations, such failures could have a material adverse effect on the Corporation, its cash flow from operations and its liquidity structure.

Expiration of Licenses and Leases

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

Exposure to Widespread Pandemic

In December 2019, COVID-19 surfaced in Wuhan, China. Since then, the outbreak has spread to over 200 countries and territories and infections have been reported around the world. The World Health Organization declared a global emergency on January 30, 2020 with respect to the outbreak and subsequently characterized it as a pandemic on March 11, 2020. In response to the outbreak, governmental authorities in Canada and internationally have introduced various recommendations and measures to try to limit the pandemic, including travel restrictions, border closures, non-essential business closures, quarantines, self-isolations, shelters-in-place and social distancing. COVID-19 and the response of governmental authorities to try to limit it are having a significant impact on the private sector and individuals, including unprecedented business, employment and economic disruptions.

The Corporation has been closely monitoring developments related to COVID-19. COVID-19 and other macroeconomic conditions around the world have contributed to a drastic decrease in global crude oil and natural gas liquids demand since the beginning of 2020. These events have resulted in significant price volatility of crude oil and liquids prices and increased economic uncertainty. Natural gas prices have also been very volatile. At this time, the extent to which COVID-19 may continue to affect the Corporation is uncertain; however, it is possible that COVID19 may have further adverse effects on commodity prices, the Corporation's business, results of operations and financial condition depending on the severity and duration of the pandemic.

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

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

Substantial Capital Requirements and Liquidity

The Corporation anticipates that it will make substantial capital expenditures for the acquisition, exploration, development and production (including facility acquisition or construction) of crude oil and natural gas reserves in the future. If the Corporation does not have or is unable to increase revenues or reserves in the future, the Corporation may have limited ability to maintain cash flow and to attract the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations or from the sale of non-core assets, will be available or sufficient to meet those requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. Moreover, future activities may require the Corporation to alter its capitalization significantly. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation’s financial condition, results of operations or prospects.

Credit Facilities Risk

The current Credit Facilities are subject to review on May 31, 2021 but may be set at an earlier or later date at the sole discretion of the Corporation's lender. There is a risk that the Credit Facilities will not be renewed for the same amount or on the same terms. There can be no assurance that the amount will be adequate for the Corporation’s future financial obligations including its capital expenditure program, or that additional funds will be available under the Credit Facilities or from other sources on terms acceptable to the Corporation.

The Corporation is required to comply with its covenants under the Credit Facilities. In the event that the Corporation does not comply with its covenants under the Credit Facilities, access to the Credit Facilities could be restricted or accelerated repayment could be required by its lenders and debt service costs would likely increase. Although the Corporation believes it is in compliance with existing covenants, compliance may not be sustainable or covenants may become increasingly onerous.

Additional Funding Requirements

The Corporation’s future cash flow may not be sufficient to fund its ongoing activities at all times. From time to time, the Corporation may require additional financing in order to carry out its crude oil and natural gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation’s future revenues decrease as a result of lower crude oil and natural gas prices or otherwise, it will affect the Corporation’s ability to attract the necessary capital to identify and increase reserves or to maintain its production. If the Corporation’s cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing or proceeds from asset sales will be available to meet this funding shortfall or will be available on terms acceptable to the Corporation.

Capital and Lending Markets

As a result of general economic uncertainties and, in particular, the low price for crude oil and natural gas, the Corporation, along with other entities having substantial exposure to crude oil and natural gas, may have reduced access to bank debt and to equity. As future capital expenditures will be financed out of cash flow, bank borrowings, if available, and possible equity issues, the Corporation's ability to do so is dependent on, among other factors, the overall state of lending and capital markets and investor and lender appetite for investments in the energy industry and the Corporation's securities in particular.

To the extent that external sources of capital become limited, unavailable or available only on onerous terms, the Corporation's ability to invest and to maintain existing assets may be impaired and its assets, liabilities, business, financial condition and results of operations may be materially and adversely affected as a result.

Based on expected funds generated from operations and bank credit availability, the Corporation believes that it has sufficient funds available to support its projected capital expenditures. However, if funds generated from operations are lower than expected or capital costs for these projects exceed current estimates, or if the Corporation incurs major unanticipated expenses related to development or maintenance of its existing properties, it may be required to seek additional capital to maintain its capital expenditures at planned levels. Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production on the Corporation's properties. The Corporation will also consider selling non-core assets to support investment programs.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation makes acquisitions and dispositions of businesses and assets that occur in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner, as well as realizing the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired businesses may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of individual properties and other assets. In this regard, non-core assets are periodically disposed of, so that the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Corporation, if disposed of, could realize less than their carrying amount on the financial statements of the Corporation.

Royalty Regimes

There can be no assurance that the governments in the jurisdictions in which the Corporation has assets will not adopt new royalty regimes, or modify the existing royalty regimes, which may have an impact on the economics of the Corporation's properties. An increase in royalties would reduce the Corporation's earnings and cash flow and could make future capital investments or the Company's operations uneconomic.

Waterflood

The Corporation may undertake certain waterflooding programs which involve the injection of water or other liquids into an oil reservoir to increase production from the reservoir and to decrease production declines. To undertake such waterflooding activities, the Corporation needs to have access to sufficient volumes of water, or other liquids, to pump into the reservoir to increase the pressure in the reservoir. There is no certainty that the Corporation will have access to the required volumes of water. In addition, in certain areas, there may be restrictions on water use for activities such as waterflooding. If the Corporation is unable to access such water it may not be able to undertake waterflooding activities, which may reduce the amount of crude 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.

Competition

The petroleum industry is competitive in all its phases. The Corporation competes with numerous other participants for the acquisition of oil and natural gas properties and in the marketing of crude oil and natural gas. The Corporation’s competitors include companies which have greater financial resources, staff, access to land and facilities than those of the Corporation. The Corporation’s ability to increase reserves in the future will depend not only on its ability to develop its present properties, but also on its ability to identify and acquire suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of crude oil and natural gas include price, methods of delivery and reliability of delivery.

The marketability of crude oil and natural gas acquired or discovered is affected by numerous factors beyond the control of the Corporation. These factors include reservoir characteristics, market fluctuations, the proximity, capacity and access to oil and natural gas pipelines and processing facilities as well as government regulation. Oil and natural gas operations (exploration, drilling, well completions and tie-ins, production, distribution, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time-to-time. The Corporation’s oil and natural gas operations are also subject to compliance with increasingly demanding federal, provincial and local laws and regulations controlling the discharge of materials into the environment or otherwise relating to the protection of the environment. Although the Corporation believes that it is in material compliance with current applicable environmental regulations, changing government regulations may have an adverse effect on the Corporation.

Environmental Regulation

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. A breach of such legislation may result in the imposition of fines, issuance of clean up orders or suspension of licences or operations by a governmental authority in respect of Altura or its properties. Such legislation may be changed to impose higher standards and potentially more costly obligations on Altura, and there can be no assurance that Altura will be able to satisfy its actual future environmental and reclamation obligations.

Actual asset retirement costs incurred in the ordinary course in a specific period will reduce the amount of cash available to the Corporation.

Abandonment and Reclamation Costs

The Corporation is required to abandon and reclaim all of its projects at the end of their economic life. These costs will be substantial. The estimate for abandonment and reclamation costs are based on a number of sources including guidelines from provincial regulatory groups, historical data from operations and management’s estimation of costs to remediate, reclaim and abandon wells and facilities in which it has a working interest.

Recently as a result of the prolonged downturn in the oil and gas industry the number of orphan wells (wells owned by insolvent parties) has increased. The cost of abandoning orphan wells has largely been funded by industry. Accordingly, the increase in the number of orphan wells could result in an increase in fees or assessments to other oil and gas producers, such as Altura, to fund the abandonment and reclamation of these orphan wells.

Management Estimates and Assumptions

In preparing consolidated financial statements estimates and assumptions are used by management in determining the reported amounts of assets and liabilities, revenues and expenses recognized during the periods presented and disclosures of contingent assets and liabilities known to exist as of the date of the financial statements. These estimates and assumptions must be made because certain information that is used in the preparation of such financial statements is dependent on future events, cannot be calculated with a high degree of precision from data available, or is not capable of being readily calculated based on generally accepted methodologies. In some cases, these estimates are particularly difficult to determine and the Corporation must exercise significant judgment. Estimates may be used in management's assessment of items such as depreciation and accretion, fair values, useful life of assets, income taxes, stock-based compensation and asset retirement obligations. Actual results for all estimates could differ materially from the estimates and assumptions used by the Corporation, which could have a material adverse effect on the financial condition, results of operations and cash flows of the Corporation.

Insurance Risks

The Corporation's property, liability and director and officer insurance are subject to deductibles, limits and exclusions, and may not provide sufficient coverage for these or other insurable risks. There can be no assurance that such insurance will continue to be offered on an economically feasible basis, that all events that could give rise to a loss or liability are insurable, or that the amounts of insurance (net of applicable deductibles) will at all times be sufficient to cover each and every loss or claim that may occur involving the assets or operations of the Corporation. Furthermore, the inability of the Corporation to obtain sufficient director and officer insurance may impact its ability to retain directors and (or) officers of the Corporation.

Carbon Pricing Risk

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

Political Uncertainty

In the last several years, the U.S. and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. Since the 2016 U.S. presidential election, the American administration has withdrawn the U.S. from the CPTPP and Congress has passed sweeping tax reform, which, among other things, significantly reduces U.S. corporate tax rates. This has affected the competitiveness of other jurisdictions, including Canada. On January 6, 2021, rioters invaded the U.S. capitol building and on January 20, 2021, Mr. Joseph Biden was sworn in as the 46th President of the United States. The political unrest associated with the former administration coming to an end and the new Biden administration taking over is unprecedented in the United States, and the short and long-term impacts on business and capital markets are unknown. Additionally, on January 20, 2021, the Biden administration announced its decision to revoke the federal permit granted by the former administration for the Keystone XL Pipeline, which has overturned a comprehensive regulatory process that lasted more than a decade. In addition, NAFTA has been replaced with the USMCA. This has affected the competitiveness of other jurisdictions, including Canada. On January 25, 2021, the Biden administration signed an executive order with respect to stringent new Made-In-America rules for the U.S. government and has indicated that the exceptions to such rules will be very limited. It is unclear what the impact of the new executive order will be and how it may impact the USMCA and the Canada-U.S. supply chain. Further, it is unclear exactly what other actions the U.S. administration will implement, and if implemented, how these actions may impact Canada and in particular the petroleum and natural gas industry. Any actions taken by the current United States administration may have a negative impact on the Canadian economy and on the businesses, financial condition, results of operations, prospects and the valuation of Canadian oil and natural gas companies, including the Corporation.

In addition to the political disruption in the U.S., the impact of the United Kingdom's exit from the European Union remains to be determined. Some European countries have also experienced the rise of antiestablishment political parties and public protests held against open-door immigration policies, trade and globalization. Conflict and political uncertainty also continues to progress in the Middle East. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement it could have an adverse effect on the Company's ability to market its products internationally, increase costs for goods and services required for operations, reduce access to skilled labour and negatively impact Altura's business, operations, financial condition and the market value of its Common Shares.

A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the oil and gas industry including the balance between economic development and environmental policy. Alberta elected a new government in 2019 that is supportive of the Trans Mountain Pipeline expansion project. In January 2020, the Supreme Court of Canada unanimously rejected the government of British Columbia's proposed regulation of the transport of heavy oil products into and through British Columbia, tensions remain high between provincial and federal governments. Continued uncertainty and delays have led to decreased investor confidence, increased capital costs and operational delays for producers and service providers operating in the jurisdictions where assets are located.

The federal government was re-elected in 2019, but in a minority position. The ability of the minority federal government to pass legislation will be subject to whether it is able to come to agreement with, and garner the support of, the other elected parties, most of whom are opposed to the development of the petroleum and natural gas industry. The minority federal government will also be required to rely on the support of the other elected parties to remain in power, which provides less stability and may lead to an earlier subsequent federal election. Lack of political consensus, at both the federal and provincial government level, continues to create regulatory uncertainty, the effects of which become apparent on an ongoing basis, particularly with respect to carbon pricing regimes, curtailment of crude oil production and transportation and export capacity, and may affect the business of participants in the petroleum and natural gas industry. See "*Industry Conditions – Climate Change Regulation*", "*Industry Conditions – Transportation Constraints, Pipeline Capacity and Market Access*", "*Industry Conditions - Curtailment" and "Industry Conditions – NAFTA/USMCA and other Trade Agreements*".

Climate Change Regulations

The Corporation's exploration and production facilities and other operations and activities emit GHG which may require the Corporation to comply with greenhouse gas emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place.

As a signatory to the *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and a signatory to the Paris Agreement, which was ratified in Canada on October 3, 2016, the Government of Canada pledged to cut its GHG emissions by 30 per cent from 2005 levels by 2030. One of the pertinent policies announced to date by the Government of Canada to reduce GHG emission is the implementation of a nation-wide price on carbon emissions. The federal carbon levy came into effect on April 1, 2019 and affects provinces which have not implemented their own carbon taxes, cap-and-trade systems or other plans for carbon pricing. The federal carbon levy had an initial rate of $20 per tonne and escalates by $10 per year until it reaches a price of $50/tonne.

The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Some of the Corporation's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing the Corporation's operating expenses and in the long-term reducing the demand for oil and gas production resulting in a decrease in the Corporation's profitability and a reduction in the value of its assets or asset write-offs. See "Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation".

Extreme hot and cold weather, heavy snowfall, heavy rainfall and wildfires may restrict or could interfere with Altura's operations, increasing costs and negatively impacting production. Moreover, extreme weather conditions may lead to disruptions in the ability to transport produced crude oil and natural gas as well as goods and services along supply chains. Certain of Altura's properties are located in regions that are proximate to forests and rivers and a wildfire or flood, respectively, may lead to significant downtime and/or damage to such assets which may affect production. At this time, the Corporation is unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting operations.

Liability Management

Alberta has developed a liability management program designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its regulatory obligations. This program involves an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is generally required. Changes to the required ratio of the Corporation's deemed assets to deemed liabilities or other changes to the requirements of liability management programs, may result in significant increases to the Corporation's compliance obligations. In addition, the liability management regime may prevent or interfere with the Corporation's ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and natural gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. The Alberta Court of Queen's Bench 2016 decision, Redwater Energy Corporation (Re), found an operational conflict between the Bankruptcy and Insolvency Act and the AER's abandonment and reclamation powers when the licensee is insolvent, which was affirmed by a majority of the Alberta Court of Appeal, and has been appealed by the AER to the Supreme Court of Canada for final determination. In response to the decision, the AER issued interim rules to administer the liability management program and until the Government of Alberta can develop new regulatory measures to adequately address environmental liabilities. There remains a great deal of uncertainty as to what new regulatory measures will be developed by the provinces or in concert with the federal government, as the final ruling will become binding in all Canadian jurisdictions.

Seasonality and Climate

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. A mild winter or wet spring may result in limited access and, as a result, reduced operations or a cessation of operations.

Municipalities and provincial transportation departments enforce road bans that restrict the movement of drilling rigs and other heavy equipment during periods of wet weather, thereby reducing activity levels. Also, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of Altura.

Alternatives to, and Changing Demand for, Petroleum Products

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and energy generation devices could reduce the demand for crude oil and other liquid hydrocarbons. Altura 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.

Reputational Risk Associated with the Corporation's Operations

The Corporation's business, operations or financial condition may be negatively impacted as a result of any negative public opinion towards the Corporation or as a result of any negative sentiment toward, or in respect of the Corporation's reputation with stakeholders, special interest groups, political leadership, the media or other entities. Public opinion may be influenced by certain media and special interest groups' negative portrayal of the industry in which the Corporation operates as well as their opposition to certain oil and natural gas projects. Potential impacts of negative public opinion or reputational issues may include delays or interruptions in operations, legal or regulatory actions or challenges, blockades, increased regulatory oversight, reduced support for, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses and increased costs and/or cost overruns. The Corporation's reputation and public opinion could also be impacted by the actions and activities of other companies operating in the oil and natural gas industry, particularly other producers, over which the Corporation has no control. In particular, the Corporation's reputation could be impacted by negative publicity related to environmental damage, loss of life, injury or damage to property caused by the Corporation's operations, or due to opposition from special interest groups opposed to oil and natural gas development. 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.

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

Changing Investor Sentiment

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

Indigenous Claims

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

Information Technology Systems and Cyber-Security

Altura depends upon the availability, capacity, reliability and security of its information technology infrastructure to conduct daily operations. Various information technology systems are relied upon to estimate reserve quantities, process and record financial data, manage the land base, analyze seismic information, administer contracts and communicate with employees and third-party partners. The Corporation is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of Altura's information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to its business activities or competitive position. Disruption of critical information technology services, or breaches of information security, could have a negative effect on the Corporation's performance and earnings, as well as reputation. Altura applies technical and process controls in line with industry-accepted standards to protect information assets and systems; however, these controls may not adequately prevent cyber-security breaches. The significance of any such event is difficult to quantify but may in certain circumstances be material and could have a material adverse effect on the Corporation's business, financial condition and results of operations.

Hedging Activities

The Corporation may enter into agreements to receive fixed or collared prices on its crude oil and natural gas production to offset the risk of revenue losses if commodity prices decline; conversely, if commodity prices increase beyond the levels set in such agreements, the Corporation will not benefit from such increases and will record losses from hedging activities based on mark-to-market measurement.

Exchange Rate Fluctuations

The Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, during the period of such agreements, the Corporation would not benefit from the changing exchange rate.

Reserves Estimate Uncertainty

There are numerous uncertainties inherent in estimating quantities of reserves and cash flows to be derived therefrom, including many factors that are beyond the control of the Corporation. The reserve and cash flow information set forth in this Annual Information Form represent estimates only. The reserves and estimated future net cash flow from the Corporation's properties have been independently evaluated, effective December 31, 2020 by McDaniel. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of crude oil and natural gas, operating costs and royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date that the relevant evaluations were prepared and many of these assumptions are subject to change and are beyond the control of the Corporation. Actual production and cash flows derived therefrom will vary from these evaluations, and such variations could be material. The foregoing evaluations are based in part on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluations.

Production

Production of crude oil and natural gas reserves at an acceptable level of profitability may not be possible during periods of low commodity prices. The Corporation will attempt to mitigate this risk by focusing on higher netback opportunities and will act as operator where possible, thus allowing the Corporation to manage costs, timing, method and marketing of production. Production risk is also addressed by concentrating exploration and development efforts in regions where infrastructure is or will be owned by the Corporation or readily accessible at an acceptable cost. In periods of low commodity prices and if netbacks are sub-economic, the Corporation may shut in production, either temporarily or permanently.

Production is also dependent in part on access to third party facilities with the result that production may be reduced by outages, accidents, maintenance programs and similar interruptions outside of the Corporation’s control.

Marketing Risks

Markets for future production of crude oil and natural gas are outside the Corporation’s capacity to control or influence and can be affected by events such as weather, climate change, regulation, regional, national and international supply and demand imbalances, facility and pipeline access, geopolitical events, currency fluctuation, introduction of new or termination of existing supply arrangements, and downtime due to maintenance or damage, either owned by the Corporation or by a third party.

Financial Risks

The Corporation may enter into transactions to acquire assets or the shares of other corporations. These transactions may be financed partially or wholly with debt, which may result in the Corporation’s debt exceeding acceptable levels. Depending on future exploration and development plans, the Corporation may require financing additional to existing resources, which may not be available or, if available, may not be available on favourable terms.

Conflicts of Interest

Certain directors of the Corporation are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA.

Reliance on Management

Shareholders will be dependent on the management of Altura in respect of the administration and management of all matters relating to Altura and its operations and administration. The loss of the services of key individuals could have a detrimental effect on Altura.

Dilution

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

Income Taxes

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

Forward-Looking Statements May Prove Inaccurate

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

MATERIAL CONTRACTS

During the year ended December 31, 2020, Altura has not entered into any contracts, nor are there any contracts still in effect, that are material to the business, other than contracts entered into in the ordinary course of business.

INTERESTS 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 under National Instrument 51-102 by the Corporation during, or related to, the Corporation's most recently completed financial year other than McDaniel, the Corporation's independent reserve evaluators, and KPMG LLP, the Corporation's auditors.

None of the principals of McDaniel had any registered or beneficial interests, direct or indirect, in any securities or other property of the Corporation or its associates or affiliates either at the time they prepared the statement, report or valuation or at any time thereafter.

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

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of the Corporation are KPMG LLP, 3100, 205 - 5th Avenue S.W., Calgary, Alberta, T2P 2V7.

The transfer agent and registrar for the Common Shares of the Corporation is Odyssey Trust Company at its office in Calgary, Alberta.

ADDITIONAL INFORMATION

Additional information relating to the Corporation may be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Common Shares and securities authorized for issuance under equity compensation plans, will be contained in the Corporation's information circular relating to the annual general meeting of shareholders to be held on June 3, 2021.

Additional financial information is provided in the Corporation's audited consolidated financial statements, and Management's Discussion and Analysis for the year ended December 31, 2020. These documents are available on the SEDAR website at www.sedar.com.

APPENDIX "A"

FORM 51-101F2
REPORT ON RESERVES DATA
BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR OF ALTURA ENERGY INC.

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

1. We have evaluated the Company's reserves data as at December 31, 2020. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2020 estimated using forecast prices and costs.

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

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

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

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved + probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2020, and identifies the respective portions thereof that we have evaluated and reported on to the Company's Board of Directors:

Altura Energy Inc.
Forecast Prices and Costs

			Net Present Value of Future Net Revenue $M (before income taxes, 10% discount rate)			
Independent Qualified Reserves Evaluator	**Effective Date of Evaluation Report**	**Location of Reserves**	**Audited**	**Evaluated**	**Reviewed**	**Total**
McDaniel	December 31, 2020	Canada	-	57,448.5	-	57,448.5

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

7. We have no responsibility to update our 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 judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

(signed)
Brian R. Hamm, P. Eng.
President & CEO

Calgary, Alberta, Canada
April 14, 2021

APPENDIX "B"

FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Altura Energy Inc. (the "**Company**") is 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 in Appendix "A" to the Annual Information Form of the Company for the year ended December 31, 2020 (the "**AIF**").

The reserves committee (the "**Reserves Committee**") of the board of directors of the Company (the "**Board of Directors**") has:

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator, McDaniel & Associates Consultants Ltd. ("**McDaniel**");

(b) met with McDaniel to determine whether any restrictions affected the ability of McDaniel to report without reservation; and inquired whether there had been disputes between the previous independent qualified reserves evaluator and management; and

(c) reviewed the reserves data with management and with McDaniel.

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

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

(b) the filing of Form 51-101F2, which is the report of McDaniel on the reserves data, contingent resources data or prospective resources data; and

(c) the content and filing of this report.

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

(signed)	(signed)
David Burghardt	Darren Gee
President & Chief Executive Officer	Director
(signed)	(signed)
Travis Stephenson	John McAleer
Vice-President, Engineering	Director

April 28, 2021

APPENDIX "C"

ALTURA ENERGY INC.
(the "Corporation")
Audit Committee
of the Board of Directors (the "Committee")

CHARTER

1. Purpose

The primary function of the Committee is to assist the Board of Directors (the "**Board**") in fulfilling its oversight responsibilities by reviewing:

(a) the financial information that will be provided to the shareholders and others;

(b) the systems of internal controls and accounting policies that management and the Board have established; and

(c) all audit processes.

Primary responsibility for the financial reporting, information systems, risk management and internal controls of the Corporation is vested in management and is overseen by the Board. Consistent with this function, the Committee should encourage continuous improvement of, and should foster adherence to, the Corporation's policies, procedures and practices at all levels. The Committee's primary duties and responsibilities are to:

(a) Serve as an independent and objective party to monitor the Corporation's financial reporting process and the system of internal controls.

(b) Monitor the independence and performance of the Corporation's external auditors.

(c) Provide an open avenue of communication among the auditors, management and the Board.

2. Composition and Process

(a) The Committee shall be comprised of at least three directors, a majority of whom are not executive officers, employees or control persons of the Corporation or of an affiliate of the Corporation in accordance with National Instrument 52-110 – *Audit Committees*.[1]

(b) Members shall be appointed by the Board on an annual basis, shall serve one-year terms and may serve consecutive terms, which are encouraged to ensure continuity of experience.

(c) The Chair of the Committee shall be appointed by the Board for a one-year term, and may serve any number of consecutive terms.

(d) The Chair shall, in consultation with management and the external auditor and internal auditor (if any), establish the agenda for the meetings and ensure that properly prepared agenda materials are circulated to the members with sufficient time for study prior to the meeting. The external auditor will also receive notice of all meetings of the Committee. The Committee may employ a list of prepared questions and considerations as a portion of its review and assessment process.

(e) The Committee shall endeavour to meet at least four times per year and may call additional meetings as required. A quorum at meetings of the Committee shall be a majority of its members. The Committee may hold its meetings, and members of the Committee may attend meetings, by telephone conference if this is deemed appropriate or make written

[1] As per National Instrument 52-110 – *Audit Committees* (Part 6) Venture issuers are exempt from the requirements of Parts 3 (*Composition of the Audit Committee*) and 5 (*Reporting Obligations*).

resolutions which must be signed by all members of the Committee.

(f) The Chair shall appoint a secretary to keep all minutes of Committee meetings, which secretary does not have to be a member of the Committee or a director.

(g) The minutes of the Committee meetings shall accurately record the decisions reached and shall be distributed to Committee members with copies to the Board, the Chief Executive Officer, the Chief Financial Officer (or persons performing similar functions) and the external auditor.

(h) The Committee reviews, prior to their presentation to the Board and their release, all material financial information required by securities regulations.

(i) The Committee enquires about potential claims, assessments and other contingent liabilities.

(j) The Committee periodically reviews with management, depreciation and amortization policies, loss provisions and other accounting policies for appropriateness and consistency.

3. Authority

(a) The Committee is appointed by the Board pursuant to provisions of the *Business Corporations Act* (Alberta) and the bylaws of the Corporation.

(b) Primary responsibility for the Corporation's financial reporting, accounting systems and internal controls is vested in senior management and is overseen by the Board. The Committee is a standing committee of the Board established to assist it in fulfilling its responsibilities in this regard. The Committee shall have responsibility for overseeing management reporting on internal controls. While it is management's responsibility to design and implement an effective system of internal control, it is the responsibility of the Committee to ensure that management has done so.

(c) The Committee shall have unrestricted access to the Corporation's personnel and documents and will be provided with the resources necessary to carry out its responsibilities.

(d) The Committee shall have direct communication channels with the internal auditors (if any) and the external auditors to discuss and review specific issues as appropriate.

(e) The Committee shall have the sole authority to retain (or terminate) independent counsel, advisors or consultants as it determines necessary to assist the Committee in discharging its functions hereunder. The Committee shall be provided with the necessary funding to compensate the independent counsel, advisors or consultants retained by the Committee.

4. Relationship with External Auditors

(a) An external auditor must report directly to the Committee.

(b) The Committee is directly responsible for overseeing the work of the external auditor engaged for the purpose of preparing or issuing an auditors' report or performing other audit, review or attest services for the issuer, including the resolution of disagreements between management and the external auditor regarding financial reporting.

(c) The Committee shall implement structures and procedures to ensure that it meets with the external auditor at least once annually in the absence of management.

5. Accounting Systems, Internal Controls and Procedures

(a) The Committee shall obtain reasonable assurance from discussions with and/or reports from management, and reports from external auditors that accounting systems are reliable and that the prescribed internal controls are operating effectively for the Corporation and its subsidiaries and affiliates.

(b) The Committee shall review to ensure to its satisfaction that adequate procedures are in place for the review of the Corporation's disclosure of financial information extracted or derived from the Corporation's financial statements and will periodically assess the adequacy of those procedures.

(c) The Committee shall review with the external auditor the quality and not just the acceptability of the Corporation's accounting principles and direct the external auditors' examinations to particular areas.

(d) The Committee will review control weaknesses identified by the external auditors, together with management's response and review with external auditors their view of the qualifications and performance of the key financial and accounting executives.

(e) In order to preserve the independence of the external auditor, the Committee will:

(i) recommend to the Board the external auditor to be nominated for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the Corporation;

(ii) recommend to the Board the compensation of the external auditor's engagement; and

(iii) review and pre-approve any engagements for non-audit services to be provided by the external auditors or its affiliates, together with estimated fees, and consider the impact, if any, on the independence of the external auditor.

(f) The Committee will review with management and with the external auditor any proposed changes in major accounting policies, the presentation and impact of significant risks and uncertainties, and key estimates and judgments of management that may be material to financial reporting.

(g) The Committee shall establish procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters and the confidential anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.

(h) The Committee shall establish a periodic review procedure to ensure that the external auditor complies with the Canadian Public Accountability Regime under Multilateral Instrument 52-108, Auditor Oversight.

(i) The Committee shall review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and former external auditor of the Corporation.

6. Statutory and Regulatory Responsibilities

(a) Annual Financial Information - review the annual audited financial statements, annual management's discussion and analysis ("MD&A") and related press releases and recommend their approval to the Board, after discussing matters such as the selection of accounting policies (and changes thereto), major accounting judgments, accruals and estimates with management and the external auditor.

(b) Interim Financial Statements - review the quarterly interim financial statements, interim MD&A and recommend their approval to the Board.

(c) Earnings Guidance/Forecasts - review any forecasted financial information and forward looking statements regarding forecasted financial information, if any.

(d) In addition, the Committee must review the Corporation's press releases pertaining to the financial statements, MD&A and earnings updates, if any, before the Corporation publicly discloses this information.

7. Reporting

(a) The Committee will report, through the Chair of the Committee, to the Board following each meeting on the major discussions and decisions made by the Committee, and report annually to the Board on the Committee's responsibilities and how it has discharged them.

(b) In addition, the Committee will review and reassess this Charter annually and recommend any proposed changes to the Board.

8. Other Responsibilities

(a) Investigating fraud, illegal acts or conflicts of interest.

(b) Discussing selected issues with counsel or the outside auditor or management.