**ALTURA ENERGY INC.**

**ANNUAL INFORMATION FORM**

**FOR THE YEAR ENDED DECEMBER 31, 2018**

**April 29, 2019**

## TABLE OF CONTENTS

DEFINITIONS ..... 1
SELECTED ABBREVIATIONS ..... 3
CONVERSION ..... 4
CURRENCY OF INFORMATION ..... 4
OIL AND GAS ADVISORIES ..... 4
NOTE REGARDING FORWARD-LOOKING STATEMENTS ..... 5
THE CORPORATION ..... 8
GENERAL DEVELOPMENT OF THE BUSINESS ..... 8
DESCRIPTION OF THE BUSINESS ..... 10
STATEMENT OF RESERVES DATA ..... 12
ADDITIONAL INFORMATION RELATING TO RESERVES DATA ..... 19
OTHER OIL AND GAS INFORMATION ..... 22
MANAGEMENT OF THE CORPORATION ..... 27
DIVIDENDS AND DISTRIBUTIONS ..... 33
DESCRIPTION OF SHARE CAPITAL ..... 33
MARKET FOR SECURITIES ..... 34
ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER ..... 34
INDUSTRY CONDITIONS ..... 34
RISK FACTORS ..... 48
MATERIAL CONTRACTS ..... 59
INTERESTS OF EXPERTS ..... 59
AUDITORS, TRANSFER AGENT AND REGISTRAR ..... 59
ADDITIONAL INFORMATION ..... 59

APPENDIX "A" – FORM 51-101F2 REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR ..... A-1

APPENDIX "B" – FORM 51-101F3 REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION ..... B-1

## 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;

"**Credit Facility**" means the $10,000,000 revolving bank facility of the Corporation, as amended from time to time;

"**development costs**" means costs incurred to develop reserves and to provide facilities for extracting, treating, gathering and storing the oil and 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 oil and 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 delay 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 March 4, 2019 and effective December 31, 2018;

"**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;

"**Performance Warrant**" has the meaning ascribed thereto under the heading "*Description of Share Capital*";

"**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, 2018 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 28° 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.

## NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain information set forth in this Annual Information Form, including management's assessment of the Corporation's future plans and operations, contains 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:

- 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;
- 2019 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, the Corporation has made assumptions regarding:

- 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 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:

- 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 corporations;
- 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 3700, 205 – 5th Avenue S.W., Bow Valley Square 2, Calgary, Alberta T2P 2V7, 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, 2016 to December 31, 2018 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 east central Alberta, central Alberta and Saskatchewan. Set out below is a review of the Corporation's activities during such three-year period.

### *2016*

*Overview of Capital Expenditure Program*

During the year ended December 31, 2016, the Corporation executed a $13.5 million capital program and drilled seven gross (6.5 net) wells in the Eyehill, Wildmere, Leduc-Woodbend and Provost areas of Alberta. Additionally, the Corporation acquired freehold and Crown leases in 34.6 sections of land in the Leduc-Woodbend area, 6.5 sections of land in the Macklin area of Saskatchewan, and 1.0 section of land in the Eyehill area. Average production for the year was 574 Boe/d.

*General Business Developments*

On June 14, 2016, the Credit Facility was decreased from $6.5 million to $4.0 million.

On September 14, 2016, the Corporation acquired an oil asset in the Killam area, strategically located in east central Alberta, for cash consideration of $4.1 million. The asset added 122 Boe/d of low decline production and included facility infrastructure and a natural gas pipeline for future growth.

On November 10, 2016, the Board of Directors approved a capital development budget of $17.0 million for 2017, funded with cash flow from operating activities and working capital. The budget included up to

11 gross (10.2 net) horizontal wells targeting the Upper Mannville Formation and land, infrastructure and seismic expenditures.

### *2017*

*Overview of Capital Expenditure Program*

During the year ended December 31, 2017, the Corporation executed a $21.2 million capital program, net of divestitures totaling $1.1 million, and drilled seven gross (7.0 net) wells in the Eyehill, Leduc-Woodbend and Killam areas of Alberta, and one gross (1.0 net) well in the Macklin area of Saskatchewan. The Corporation invested $3.8 million into facilities and pipelines and acquired freehold and Crown leases in 19 sections of land in the Leduc-Woodbend area, and 3 sections of land in the Macklin area of Saskatchewan. Average production for the year was 1,128 Boe/d.

*General Business Developments*

On June 2, 2017, the Credit Facility was increased from $4.0 million to $7.5 million.

On October 3, 2017, the Credit Facility was increased from $7.5 million to $10.0 million.

On December 14, 2017, the Board of Directors approved a preliminary 2018 capital development budget of $15.0 million, funded with cash flow from operating activities and the Credit Facility. The capital development budget is split approximately 60% to drilling, completion, equipping and tie-in capital and 40% to infrastructure and other capital.

### *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 extended reach horizontal ("**ERH**") wells at Leduc-Woodbend, and one well at Macklin. The Corporation invested in key infrastructure at Leduc-Woodbend including the construction of a multi-well battery and a natural gas gathering pipeline that connects Altura's northern area production to a second 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 Credit Facility 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 percent 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 percent oil & liquids) of low decline, Glauconitic oil (33° API) production.

On December 13, 2018, the Credit Facility 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 percent 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 percent oil & liquids) of low decline, Glauconitic oil (33° API) production.

**Recent Developments**

On March 5, 2019, the Board of Directors approved an initial 2019 capital budget of $15.0 million, funded with cash flow from operating activities and the Credit Facility. The budget is weighted to the second half of 2019 and includes drilling four ERH wells at Leduc-Woodbend. Additionally, Altura plans to implement a waterflood pilot project which includes drilling on reduced inter-well spacing.

On March 21, 2019, the Corporation confirmed its 2019 capital budget of $15.0 million.

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 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.

**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, oil and gas has several inherent risks. See "*Risk Factors*" in this AIF.

**Employees**

As at December 31, 2018, 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 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. See "*Risk Factors – Competition*".

**Cyclical Nature of Business**

The Corporation's business is often driven by weather conditions and the health of the economy. Demand for oil and 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 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. See "*Risk Factors – Volatility of Oil and Gas Prices and General Economic Conditions*".

## 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, 2018 and a preparation date of March 4, 2019. The Reserves Data summarizes the 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 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, 2018 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 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)*

**Summary of Oil & Gas Reserves**
**Forecast Prices and Costs as of December 31, 2018**
**Total Company**

| | Reserves | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Light & Medium Oil | | Heavy 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 | 213.4 | 180.7 | 1,013.5 | 910.4 | 2,560.8 | 2,333.4 | 70.9 | 60.5 |
| Non-Producing | 0.0 | 0.0 | 106.0 | 95.3 | 181.6 | 164.5 | 4.5 | 4.0 |
| Undeveloped | 0.0 | 0.0 | 3,107.7 | 2,738.2 | 6,764.6 | 6,058.2 | 169.1 | 144.5 |
| **Total Proved** | **213.4** | **180.7** | **4,227.2** | **3,744.0** | **9,507.0** | **8,556.0** | **244.6** | **209.0** |
| **Total Probable** | 62.8 | 52.7 | 2,590.4 | 2,212.8 | 6,264.8 | 5,575.4 | 158.7 | 128.6 |
| **Total Proved & Probable** | **276.2** | **233.4** | **6,817.6** | **5,956.8** | **15,771.8** | **14,131.4** | **403.2** | **337.6** |

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

**Summary of Net Present Value of Future Net Revenue**
**Forecast Prices and Costs as of December 31, 2018**
**Total Company**

| | Net Present Values of Future Net Revenue | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Before Income Taxes Discounted at (%/year) | | | | | After Income Taxes Discounted at (%/year) | | | | | |
| Reserves Category | @0.0% (M$) | @5.0% (M$) | @10.0% (M$) | @15.0% (M$) | @20.0% (M$) | @0.0% (M$) | @5.0% (M$) | @10.0% (M$) | @15.0% (M$) | @20.0% (M$) | Unit Value Before Tax @10.0% (1) ($/BOE) |
| **Proved** | | | | | | | | | | | |
| Developed Producing | 40,085 | 36,613 | 33,645 | 31,155 | 29,068 | 40,085 | 36,613 | 33,645 | 31,155 | 29,068 | 21.84 |
| Non-Producing | 3,903 | 3,592 | 3,330 | 3,109 | 2,923 | 3,006 | 2,900 | 2,787 | 2,676 | 2,573 | 26.27 |
| Undeveloped | 59,568 | 44,019 | 32,576 | 24,117 | 17,793 | 42,563 | 29,894 | 20,646 | 13,900 | 8,940 | 8.37 |
| **Total Proved** | **103,556** | **84,224** | **69,551** | **58,381** | **49,784** | **85,653** | **69,407** | **57,078** | **47,731** | **40,581** | **12.51** |
| **Total Probable** | 93,012 | 64,848 | 47,070 | 35,471 | 27,611 | 68,133 | 47,146 | 33,843 | 25,199 | 19,389 | 14.16 |
| **Total Proved & Probable** | **196,568** | **149,072** | **116,621** | **93,852** | **77,395** | **153,786** | **116,553** | **90,921** | **72,931** | **59,970** | **13.13** |

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

## Total Future Net Revenue (Undiscounted)
## Forecast Prices and Costs as of December 31, 2018
## Total Company

| 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 | 312,073 | 37,649 | 90,647 | 75,327 | 4,895 | 103,556 | 17,903 | 85,653 |
| Total Proved & Probable Reserves | 530,437 | 69,327 | 162,767 | 95,471 | 6,304 | 196,568 | 42,782 | 153,786 |

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

## Future Net Revenue by Product Type
## Forecast Prices and Costs as of December 31, 2018
## Total Company

| Reserves Category | Product Type | Future Net Revenue Before Income Taxes (discounted @ 10%) M$ | Unit Value (1) \$/Mcf \$/bbl |
|---|---|---|---|
| **Total Proved Reserves** | Light and Medium Oil (Including Solution Gas and By-products) | 3,394 | 18.79 |
| | Heavy Oil (Including Solution Gas and By-products) | 66,156 | 17.67 |
| | **Total** | **69,551** | |
| **Total Proved & Probable Reserves** | Light and Medium Oil (Including Solution Gas and By-products) | 4,330 | 18.56 |
| | Heavy Oil (Including Solution Gas and By-products) | 112,291 | 18.85 |
| | **Total** | **116,621** | |

(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, 2018, were $43.46/Bbl for heavy oil, $57.94/Bbl for light and medium oil, $1.63/Mcf for natural gas and $47.57/Bbl for NGLs. McDaniel employed the following pricing, exchange rate and inflation rate assumptions as of December 31, 2018 in the McDaniel Report in estimating reserves data using forecast prices and costs. Benchmark weighted average historical prices for 2018 are also reflected in the tables below.

## 3 Consultant Average Prices (McDaniel, GLJ and Sproule)

### Summary of Crude Oil and Natural Gas Liquids Price Forecasts

### January 1, 2019

| Year | WTI Crude Oil $US/bbl | Brent Crude Oil $US/bbl | Edmonton Light Crude Oil $C/bbl | Alberta Bow River Hardisty Crude Oil $C/bbl | Western Canadian Select Crude Oil $C/bbl | Alberta Heavy Crude Oil $C/bbl | Sask Cromer Medium Crude Oil $C/bbl | Edmonton Cond. & Natural Gasolines $/bbl | Edmonton Ethane $/bbl | Edmonton Propane $/bbl | Edmonton Butanes $/bbl | Inflation % | US/CAN Exchange Rate $US/$CAN |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | | | | | | |
| **History** | | | | | | | | | | | | | |
| 2018 | 65.00 | 71.30 | 72.20 | 54.00 | 52.70 | 42.90 | 71.10 | 80.80 | NA | 27.55 | 32.80 | | 0.770 |
| **Forecast** | | | | | | | | | | | | | |
| 2019 | 58.58 | 65.92 | 67.30 | 52.61 | 51.55 | 43.92 | 63.99 | 70.10 | 6.82 | 26.13 | 27.32 | 0.0 | 0.757 |
| 2020 | 64.60 | 69.47 | 75.84 | 60.50 | 59.58 | 52.76 | 71.38 | 79.21 | 8.40 | 31.27 | 41.10 | 2.0 | 0.782 |
| 2021 | 68.20 | 71.65 | 80.17 | 66.60 | 65.89 | 59.10 | 75.14 | 83.33 | 9.98 | 34.58 | 49.28 | 2.0 | 0.797 |
| 2022 | 71.00 | 73.72 | 83.22 | 69.32 | 68.61 | 61.60 | 78.06 | 86.20 | 11.22 | 37.25 | 55.65 | 2.0 | 0.803 |
| 2023 | 72.81 | 75.58 | 85.34 | 71.25 | 70.53 | 63.39 | 80.06 | 88.16 | 11.89 | 38.73 | 57.92 | 2.0 | 0.807 |
| 2024 | 74.59 | 77.39 | 87.33 | 73.07 | 72.34 | 65.14 | 81.96 | 90.20 | 12.22 | 39.75 | 59.27 | 2.0 | 0.808 |
| 2025 | 76.42 | 79.27 | 89.50 | 75.08 | 74.31 | 66.99 | 84.02 | 92.43 | 12.45 | 40.76 | 60.77 | 2.0 | 0.808 |
| 2026 | 78.40 | 81.27 | 91.89 | 77.22 | 76.44 | 69.06 | 86.29 | 94.87 | 12.71 | 41.93 | 62.37 | 2.0 | 0.808 |
| 2027 | 79.98 | 82.88 | 93.76 | 78.89 | 78.10 | 70.60 | 88.08 | 96.80 | 12.96 | 42.84 | 63.65 | 2.0 | 0.808 |
| 2028 | 81.59 | 84.54 | 95.68 | 80.60 | 79.81 | 72.17 | 89.90 | 98.79 | 13.28 | 43.80 | 64.97 | 2.0 | 0.808 |
| 2029 | 83.22 | 86.23 | 97.60 | 82.21 | 81.41 | 73.62 | 91.69 | 100.76 | 13.54 | 44.68 | 66.27 | 2.0 | 0.808 |
| 2030 | 84.89 | 87.95 | 99.55 | 83.86 | 83.04 | 75.09 | 93.53 | 102.78 | 13.81 | 45.57 | 67.60 | 2.0 | 0.808 |
| 2031 | 86.58 | 89.71 | 101.54 | 85.54 | 84.70 | 76.59 | 95.40 | 104.83 | 14.09 | 46.48 | 68.95 | 2.0 | 0.808 |
| 2032 | 88.31 | 91.51 | 103.57 | 87.25 | 86.39 | 78.12 | 97.31 | 106.93 | 14.37 | 47.41 | 70.33 | 2.0 | 0.808 |
| 2033 | 90.08 | 93.34 | 105.64 | 88.99 | 88.12 | 79.68 | 99.25 | 109.07 | 14.66 | 48.36 | 71.74 | 2.0 | 0.808 |
| Thereafter | +2%/yr | +2%/yr | +2%/yr | +2%/yr | +2%/yr | +2%/yr | +2%/yr | +2%/yr | +2%/yr | +2%/yr | +2%/yr | 2.0 | 0.808 |

(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

# 3 Consultant Average Prices (McDaniel, GLJ and Sproule)

## Summary of Natural Gas Price Forecasts

## January 1, 2019

| Year | U.S. Henry Hub Gas Price $US/MMBtu | Alberta AECO Spot Price $C/MMBtu | Alberta Average Plantgate $C/MMBtu (1) | 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 |
|---|---|---|---|---|---|---|---|---|
| **History** | | | | | | | | |
| 2018 | 3.05 | 1.55 | 1.35 | 1.35 | 2.85 | 1.65 | 1.20 | 1.40 |
| **Forecast** | | | | | | | | |
| 2019 | 3.00 | 1.88 | 1.70 | 1.70 | 2.88 | 1.80 | 1.31 | 1.47 |
| 2020 | 3.13 | 2.31 | 2.10 | 2.10 | 3.01 | 2.20 | 1.82 | 1.99 |
| 2021 | 3.33 | 2.74 | 2.55 | 2.55 | 3.19 | 2.65 | 2.29 | 2.46 |
| 2022 | 3.51 | 3.05 | 2.85 | 2.85 | 3.20 | 2.95 | 2.63 | 2.81 |
| 2023 | 3.62 | 3.21 | 3.00 | 3.00 | 3.40 | 3.10 | 2.81 | 2.98 |
| 2024 | 3.70 | 3.31 | 3.10 | 3.10 | 3.45 | 3.20 | 2.93 | 3.11 |
| 2025 | 3.77 | 3.39 | 3.15 | 3.15 | 3.55 | 3.25 | 2.99 | 3.16 |
| 2026 | 3.85 | 3.46 | 3.25 | 3.25 | 3.65 | 3.35 | 3.06 | 3.24 |
| 2027 | 3.92 | 3.54 | 3.30 | 3.30 | 3.70 | 3.40 | 3.13 | 3.31 |
| 2028 | 4.01 | 3.62 | 3.40 | 3.40 | 3.80 | 3.50 | 3.22 | 3.40 |
| 2029 | 4.09 | 3.69 | 3.45 | 3.45 | 3.90 | 3.55 | 3.28 | 3.47 |
| 2030 | 4.17 | 3.77 | 3.50 | 3.50 | 3.95 | 3.60 | 3.35 | 3.54 |
| 2031 | 4.25 | 3.84 | 3.60 | 3.60 | 4.05 | 3.75 | 3.41 | 3.61 |
| 2032 | 4.34 | 3.92 | 3.65 | 3.65 | 4.10 | 3.80 | 3.48 | 3.68 |
| 2033 | 4.42 | 4.00 | 3.75 | 3.75 | 4.20 | 3.90 | 3.55 | 3.75 |
| Thereafter | +2%/yr | +2%/yr | +2%/yr | +2%/yr | +2%/yr | +2%/yr | +2%/yr | +2%/yr |

(1) 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, 2018, derived from the McDaniel Report using forecast prices and cost estimates, reconciled to the Corporation's gross reserves as at December 31, 2017.

**Reconciliation of Company Gross Reserves by Product Type**
**Forecast Prices and Costs as of December 31, 2018**
**Total Company**

| | LIGHT CRUDE OIL AND MEDIUM CRUDE OIL | | | HEAVY OIL | | | CONVENTIONAL GAS | | |
|---|---|---|---|---|---|---|---|---|---|
| FACTORS | Gross Proved Mbbl | Gross Probable Mbbl | Gross Proved Plus Probable Mbbl | Gross Proved Mbbl | Gross Probable Mbbl | Gross Proved Plus Probable Mbbl | Gross Proved MMcf | Gross Probable MMcf | Gross Proved Plus Probable MMcf |
| December 31, 2017 | 1,139.4 | 588.1 | 1,727.5 | 1,284.1 | 1,288.8 | 2,572.9 | 3,623.2 | 1,986.7 | 5,609.8 |
| Extensions & Improved Recovery(1) | - | - | - | 3,255.2 | 2,226.3 | 5,481.4 | 6,977.3 | 5,292.3 | 12,269.6 |
| Technical Revisions(2) | (12.6) | 0.0 | (12.6) | 309.1 | (314.9) | (5.8) | 1,262.6 | (222.0) | 1,040.5 |
| Discoveries | - | - | - | - | - | - | - | - | - |
| Acquisitions(3) | 222.1 | 62.8 | 285.0 | - | - | - | 95.0 | 27.1 | 122.1 |
| Dispositions(4) | (1,065.1) | (588.1) | (1,653.2) | (358.3) | (609.8) | (968.1) | (1,951.3) | (819.2) | (2,770.6) |
| Economic Factors | - | - | - | - | - | - | - | - | - |
| Production(5) | (70.4) | - | (70.4) | (262.8) | - | (262.8) | (499.7) | - | (499.7) |
| December 31, 2018 | 213.4 | 62.8 | 276.2 | 4,227.2 | 2,590.4 | 6,817.6 | 9,507.0 | 6,264.8 | 15,771.8 |

| | NATURAL GAS LIQUIDS | | | TOTAL | | |
|---|---|---|---|---|---|---|
| FACTORS | Gross Proved Mbbl | Gross Probable Mbbl | Gross Proved Plus Probable Mbbl | Gross Proved Mboe | Gross Probable Mboe | Gross Proved Plus Probable Mboe |
| December 31, 2017 | 80.1 | 54.5 | 134.5 | 3,107.4 | 2,262.5 | 5,369.9 |
| Extensions & Improved Recovery(1) | 174.4 | 132.3 | 306.7 | 4,592.5 | 3,240.6 | 7,833.1 |
| Technical Revisions(2) | 10.3 | (21.3) | (11.0) | 517.2 | (373.2) | 144.0 |
| Discoveries | - | - | - | - | - | - |
| Acquisitions(3) | 9.5 | 2.7 | 12.2 | 247.4 | 70.1 | 317.5 |
| Dispositions(4) | (18.8) | (9.5) | (28.3) | (1,767.4) | (1,344.0) | (3,111.4) |
| Economic Factors | - | - | - | - | - | - |
| Production(5) | (11.0) | - | (11.0) | (427.5) | - | (427.5) |
| December 31, 2018 | 244.6 | 158.7 | 403.2 | 6,269.7 | 3,856.0 | 10,125.7 |

(1) The extensions and improved recovery amount includes all new wells drilled and booked during the year.
(2) The technical revisions amount includes all changes in reserves due to well performance and all previously booked wells which were drilled during the year.
(3) The acquisitions amount is the estimate of reserves at December 31, 2018, plus any production from the acquisition dates to December 31, 2018.
(4) The dispositions amount relates to the Provost Disposition on May 31, 2018.
(5) Altura produced an average of 1,172 Boe per day in 2018.

## 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 and Medium Oil (Mbbl) | | Heavy 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 |
| 2016 | 58.2 | 467.9 | 116.3 | 116.3 | 51.8 | 803.6 | 0.9 | 4.1 |
| 2017 | - | 294.8 | 707.5 | 825.4 | 948.4 | 1,538.4 | 36.5 | 39.6 |
| 2018 | - | - | 2,778.1 | 3,107.7 | 6,046.7 | 6,764.6 | 151.2 | 169.1 |

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 4,404.2 Mboe of proved undeveloped reserves in the McDaniel Report with $75.3 million of associated undiscounted capital, of which $32.7 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 and Medium Oil (Mbbl) | | Heavy 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 |
| 2016 | 316.1 | 610.3 | 262.5 | 262.5 | 362.2 | 758.0 | 8.4 | 11.1 |
| 2017 | - | 306.3 | 828.1 | 1,129.6 | 731.6 | 1,340.2 | 28.2 | 40.7 |
| 2018 | - | - | 2,083.6 | 2,203.6 | 4,949.9 | 5,249.4 | 123.7 | 131.2 |

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 3,209.7 Mboe of probable undeveloped reserves in the McDaniel Report with $20.1 million of associated undiscounted capital, of which $nil is forecast to be spent in the first two years.

The Corporation's probable 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 substantially all of its currently booked undeveloped projects will be completed within a four-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 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. See "*Risk Factors – Reserves Estimate Uncertainty*".

## 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.

As at December 31, 2018 the Corporation had 43.5 net wells for which it expects to incur abandonment and reclamation costs. The McDaniel Report deducted $6.3 million (undiscounted) and $0.8 million (10% discount) for abandonment and reclamation costs of wells with proved and probable reserves, in estimating the future net revenues disclosed in this AIF.

The future net revenues disclosed in this AIF based on the McDaniel Report do not contain an allowance for abandonment and reclamation costs for facilities, pipelines or wells without reserves. Management has also estimated there is an additional $4.0 million (undiscounted and un-escalated) and $1.4 million (10% discount, 2% inflation rate) not included in the future net revenues disclosed in this AIF for abandonment and reclamation costs for facilities and pipelines and for abandonment and reclamation costs for wells without reserves. Over the next three years, the Corporation anticipates that a total of $0.3 million on an undiscounted basis, will be incurred 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** |
| 2019 | 10,200 | 10,200 |
| 2020 | 22,468 | 22,468 |
| 2021 | 30,152 | 30,152 |
| 2022 | 12,506 | 32,650 |
| 2023 | - | - |
| Thereafter | - | - |
| Total for all years undiscounted | 75,326 | 95,470 |
| Total for all years discounted at 10% per year | 61,872 | 76,354 |

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 of 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 Area*

Since 2015 the Corporation acquired land through Crown land sales and land acquisitions in the Leduc-Woodbend area of Alberta. Altura currently holds a 98.4% working interest in 45,702 acres of land in the Leduc-Woodbend area, of which 33,521 net acres are undeveloped and 11,465 net acres are developed. Altura drilled nine wells in the area in 2018, of which eight were brought on production in 2018 and one was brought on production in the first quarter of 2019. The Corporation's development and production activities in the Leduc-Woodbend area are directed towards 17° API oil in the Upper Mannville Formation.

McDaniel assigned 6,031.8 Mboe of proved reserves and 9,817.8 Mboe of proved plus probable reserves in the Leduc-Woodbend area in the McDaniel Report.

During the year ended December 31, 2018, Altura had average production of approximately 860 Boe/d (including 689 Bbls/d of oil and liquids and 1,023 Mcf/d of natural gas) from 12 gross (12.0 net) producing wells in the area. Production in the area was tied into one multi-well battery and three single well batteries owned and operated by the Corporation. 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 Area*

In 2018, the Corporation closed two acquisitions in the Leduc-Woodbend area of Alberta, which included 3.0 net sections of land in the Upper Mannville oil pool and a 59.89% WI, including operatorship, in the Glauconitic D Unit No. 1 oil pool. Altura currently holds a 59.89% working interest in 1,920 acres of land in the Leduc-Woodbend Glauconitic area, of which all 1,150 net acres are developed.

McDaniel assigned 237.9 Mboe of proved reserves and 308.0 Mboe of proved plus probable reserves in the Leduc-Woodbend Glauconitic area in the McDaniel Report.

During the year ended December 31, 2018, Altura had average production of approximately 25 Boe/d (including 23 Bbls/d of oil and liquids and 9 Mcf/d of natural gas) from 10 gross (6.8 net) producing wells in the area. Production in the area is tied into a 59.89% WI multi-well battery, operated by the Corporation. Oil sales volumes are trucked to multiple sales points and natural gas production is transported via pipeline and processed by a third-party operator.

## Oil and Natural Gas Wells

The following table sets forth the number and status of the Corporation's wells effective December 31, 2018.

| | Oil Wells | | | | Natural Gas Wells | | | |
|---|---|---|---|---|---|---|---|---|
| | Producing | | Non-Producing | | Producing | | Non-Producing | |
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net |
| Alberta | 22 | 18.8 | 34 | 24.7 | - | - | - | - |
| Total | 22 | 18.8 | 34 | 24.7 | - | - | - | - |

**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.

Of the non-producing wells, one oil well was drilled in 2018 that was capable of production and had reserves assigned to it. The well was equipped for production in January 2019 and commenced production in February 2019.

## Properties with no Attributed Reserves

The following table summarizes, effective December 31, 2018, 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 could expire within one year.

| | Gross Acres | Net Acres | Net Acres Expiring Within One Year |
|---|---|---|---|
| Canada | 47,623 | 46,901 | 2,560 |
| Total | 47,623 | 46,901 | 2,560 |

## 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 oil and 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. See "*Risk Factors – Substantial Capital Requirements and Liquidity*".

The significant economic factors that affect Altura's development of its lands to which no reserves have been attributed are future commodity prices for oil and 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 have the potential to accelerate development activities and enhance the economics relating to such lands.

**Forward Contracts**

The Corporation's contracts to sell crude oil, natural gas and NGLs are at prevailing market pricing. The Corporation has no commodity price hedges.

**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 2020. See "*Risk Factors – Income Taxes*".

**Costs Incurred**

The following table summarizes capital expenditures, excluding property dispositions, incurred by the Corporation during the year ended December 31, 2018.

| | **Property Acquisitions** | | | |
|---|---|---|---|---|
| **($000s)** | **Proved Properties** | **Unproved Properties** | **Exploration Costs** | **Development Costs** |
| Total | 2,994 | 603 | 758 | 32,698 |

**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, 2018. All wells were drilled in Canada.

| | **Exploratory Wells** | | **Development Wells** | |
|---|---|---|---|---|
| | **Gross** | **Net** | **Gross** | **Net** |
| Crude Oil | - | - | 10 | 9.95 |
| Natural Gas | - | - | - | - |
| Service | - | - | - | - |
| Stratigraphic Test | - | - | - | - |
| Dry | - | - | - | - |
| Total | - | - | 10 | 9.95 |

### Planned Capital Expenditures

In March 2019, Altura announced its initial capital expenditure budget of $15.0 million for 2019, which was confirmed on March 21, 2019. The budget is weighted to the second half of 2019 and includes drilling four gross (4.0 net) extended reach horizontal wells at Leduc-Woodbend. Additionally, Altura plans to implement a waterflood pilot project which includes drilling on reduced inter-well spacing.

Management intends to continuously monitor well performance and commodity prices throughout the year and may at any time adjust the 2019 capital program if well performance is exceeding expectations or if oil prices deteriorate or strengthen. The budget leaves Altura with a conservative balance sheet and the flexibility to accelerate development in the second half of 2019 if results and commodity prices are supportive.

### Production Estimates

The following table discloses for each product type the total volume of production estimated by McDaniel in the McDaniel Report for 2019 in the estimates of future net revenue from gross proved and gross proved plus probable reserves disclosed above.

| | Light & 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 | 115 | 1,037 | 2,179 | 58 | 1,574 |
| Developed Non-Producing | - | 127 | 115 | 3 | 149 |
| Undeveloped | - | 263 | 260 | 7 | 312 |
| **TOTAL PROVED** | 115 | 1,427 | 2,554 | 68 | 2,035 |
| **TOTAL PROBABLE** | 2 | 94 | 197 | 5 | 134 |
| **TOTAL PROVED & PROBABLE** | 117 | 1,521 | 2,751 | 73 | 2,169 |

The estimated production volumes for the Leduc-Woodbend property, which accounts for 94% of McDaniel's total forecast production for the year ending December 31, 2019, is set forth below.

| | Leduc-Woodbend Total Oil Equivalent Boe/d |
|---|---|
| **PROVED** | |
| Developed Producing | 1,446 |
| Developed Non-Producing | 149 |
| Undeveloped | 312 |
| **TOTAL PROVED** | 1,907 |
| **TOTAL PROBABLE** | 131 |
| **TOTAL PROVED & PROBABLE** | 2,038 |

## Production History

The following table discloses, on a quarterly basis for the year ended December 31, 2018, certain information in respect of the Corporation's production, product prices received, royalties paid, operating expenses and resulting netback by primary product type.

| | Quarter Ended 2018 | | | | Year Ended |
|---|---|---|---|---|---|
| | Mar. 31 | Jun. 30 | Sep. 30 | Dec. 31 | Dec. 31, 2018 |
| **Average Daily Production[(1)]** | | | | | |
| Light and Medium Crude Oil (Bbls/d)[(2)] | 527 | 344 | 23 | 74 | 240 |
| Heavy Crude Oil (Bbls/d) [(2)] | 661 | 624 | 1,037 | 1,338 | 917 |
| Conventional Natural Gas (Mcfe/d) [(3)] | 157 | 145 | 45 | - | 86 |
| Combined (Boe/d) | 1,215 | 991 | 1,067 | 1,412 | 1,172 |
| **Average Net Production Prices Received** | | | | | |
| Light and Medium Crude Oil ($/Bbl) [(2)] | 42.91 | 55.90 | 67.29 | 52.66 | 48.87 |
| Heavy Crude Oil ($/Bbl) [(2)] | 40.97 | 47.84 | 47.91 | 21.96 | 37.12 |
| Conventional Natural Gas ($/Mcfe) [(3)] | 5.01 | 2.76 | 7.38 | - | 4.39 |
| Combined ($/Boe) | 41.58 | 49.87 | 48.29 | 23.57 | 39.40 |
| **Royalties Paid** | | | | | |
| Light and Medium Crude Oil ($/Bbl) [(2)] | 4.26 | 6.80 | 11.58 | 11.34 | 5.89 |
| Heavy Crude Oil ($/Bbl) [(2)] | 4.68 | 3.66 | 4.39 | 1.91 | 3.40 |
| Conventional Natural Gas ($/Mcfe) [(3)] | 1.05 | 0.24 | 1.55 | - | 0.78 |
| Combined ($/Boe) | 4.54 | 4.69 | 4.57 | 2.40 | 3.93 |
| **Production Costs** | | | | | |
| Light and Medium Crude Oil ($/Bbl) [(2)] | 14.96 | 12.36 | 28.17 | 34.70 | 15.88 |
| Heavy Crude Oil ($/Bbl) [(2)] | 10.27 | 14.13 | 8.88 | 7.17 | 9.39 |
| Conventional Natural Gas ($/Mcfe) [(3)] | 4.50 | 5.35 | 0.78 | - | 4.37 |
| Combined ($/Boe) | 12.66 | 13.96 | 9.26 | 8.61 | 10.93 |
| **Netback Received[(4)]** | | | | | |
| Light and Medium Crude Oil ($/Bbl) [(2)] | 23.69 | 36.74 | 27.54 | 6.62 | 27.10 |
| Heavy Crude Oil ($/Bbl) [(2)] | 26.02 | 30.05 | 34.64 | 12.88 | 24.33 |
| Conventional Natural Gas ($/Mcfe) [(3)] | (0.54) | (2.83) | 5.05 | - | (0.76) |
| Combined ($/Boe) | 24.38 | 31.22 | 34.46 | 12.56 | 24.54 |

**Notes:**

(1) Before the deduction of royalties.

(2) Includes solution gas and associated by-products.

(3) Includes associated by-products.

(4) Netbacks are calculated by subtracting royalties and production costs 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, 2018.

| | Light & 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 | - | 665 | 24 | 1,022 | 860 | 73 |
| Leduc-Woodbend Glauconitic | 22 | - | 1 | 9 | 25 | 2 |
| Eyehill[(1)] | 129 | - | 3 | 165 | 159 | 13 |
| Killam[(1)] | 29 | - | - | 119 | 49 | 4 |
| Wildmere[(1)] | - | 24 | - | - | 24 | 2 |
| Macklin[(1)] | - | 31 | - | - | 31 | 3 |
| Eyehill South[(1)] | 9 | - | - | - | 9 | 1 |
| Provost Minor[(1)] | 2 | - | - | 29 | 7 | 1 |
| Other minor area[(2)] | 2 | - | 2 | 25 | 8 | 1 |
| Total | 193 | 720 | 30 | 1,369 | 1,172 | 100 |

**Notes:**

(1) Property sold in the Provost Disposition on May 31, 2018.
(2) Property sold on August 1, 2018.

## 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<br>Calgary, Alberta | President, Chief Executive Officer and Director | July 31, 2015 |
| Tavis Carlson<br>Calgary, Alberta | Vice-President, Finance and Chief Financial Officer and Secretary | September 1, 2015 |
| Travis Stephenson<br>Calgary, Alberta | Vice-President, Engineering | July 31, 2015 |
| Robert Pinckston<br>Calgary, Alberta | Vice-President, Exploration | July 31, 2015 |
| Jeff Mazurak<br>Calgary, Alberta | Vice-President, Operations | July 31, 2015 |
| Craig Stayura<br>Calgary, Alberta | Vice-President, Land | March 22, 2017 |
| John McAleer[(1)(2)(3)]<br>Calgary, Alberta | Director | July 31, 2015 |

| Name and Municipality of Residence | Position Held | Date First Elected or Appointed |
|---|---|---|
| Brian Lavergne(2)(3)<br>Calgary, Alberta | Director | July 31, 2015 |
| Darren Gee(1)(2)<br>Calgary, Alberta | Director | July 31, 2015 |
| Robert Maitland(1)(3)<br>Victoria, British Columbia | Director | July 31, 2015 |

**Notes:**
(1) Member of the Audit Committee.
(2) Member of the Reserves Committee.
(3) Member of the Compensation 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 10,839,399 Common Shares representing 10.0% 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 32 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 Accountant with 17 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 until its purchase by Storm Resources Ltd. ("**Storm**") in

2012. Such role involved significant acquisition and development (asset and corporate) and equity financing activities as he oversaw the overall finance and accounting functions of the firm. Most recently, Mr. Carlson was the Controller of Manitok Energy Inc. from 2012 to August 2015, with responsibility for the accounting department and the cash flow forecasting and budgeting process.

Mr. Carlson graduated from the University of Alberta in 2002 with a Bachelor of Commerce degree and has been a Chartered Accountant since 2005.

**Travis Stephenson, Vice-President, Engineering**

Mr. Stephenson is a Professional Engineer with 19 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 30 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 15 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 $350MM. 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 12 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 28 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.

**Brian Lavergne, Director**

Mr. Lavergne is President, CEO and a director of Storm, a corporation engaged in the exploration for, and the acquisition, development and production of oil, natural gas and natural gas liquids reserves in the Provinces of Alberta and British Columbia and was an executive with the prior Storm entities since 1998. From 1994 to 1998, Mr. Lavergne was employed by Renaissance in positions of increasing responsibility including Exploitation Manager and Operations District Manager. Mr. Lavergne earned a BSc in Mechanical Engineering from the University of Alberta (1989) and is registered as a P.Eng. with APEGA.

**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 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 BComm 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.

**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, 2018; (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, 2018.

**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.

## 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, 2018 and as at April 29, 2019, an aggregate of 108,920,973 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, 2018 the Corporation had outstanding a total of 8,390,000 Options to purchase Common Shares issued to its directors and officers exercisable at a weighted average price of $0.34 per Common Share with expiry dates ending November 30, 2023. As at the date hereof, the Corporation has outstanding a total of 9,570,000 Options. As at April 29, 2019, 5,410,002 Options have vested and are exercisable at an average price of $0.33 per Common Share.

### Warrants

As at December 31, 2018, and as at the date hereof the Corporation had a total of 97,498,785 performance warrants outstanding with expiry dates ending August 28, 2020 (the "**Performance Warrants**"). Every ten Performance Warrants entitle the holder thereof to purchase one Common Share at a price of $0.449 per Common Share within five years from the date of issuance, with one-third vesting each of when the 20-day volume weighted average price of the Common Shares meets or exceeds $0.675, $0.901 and $1.124, respectively. As at April 29, 2019, no Performance Warrants have vested.

## 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, 2018 to December 31, 2018.

| Month | High ($) | Low ($) | Volume |
|---|---|---|---|
| January 2018 | 0.435 | 0.355 | 2,767,385 |
| February 2018 | 0.36 | 0.32 | 948,095 |
| March 2018 | 0.38 | 0.335 | 1,566,837 |
| April 2018 | 0.44 | 0.335 | 1,630,250 |
| May 2018 | 0.63 | 0.38 | 11,898,387 |
| June 2018 | 0.64 | 0.53 | 3,523,979 |
| July 2018 | 0.65 | 0.56 | 2,643,604 |
| August 2018 | 0.70 | 0.495 | 3,452,817 |
| September 2018 | 0.56 | 0.51 | 1,622,557 |
| October 2018 | 0.55 | 0.43 | 2,768,545 |
| November 2018 | 0.47 | 0.375 | 1,832,425 |
| December 2018 | 0.47 | 0.335 | 1,541,962 |

During the financial year ended December 31, 2018, no Common Shares were issued, and the Corporation granted an aggregate of 1,180,000 Options with an exercise price of $0.375 per Common Share.

## 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 oil and gas, oil and 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

### *Oil*

In Canada, producers of oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. The price depends in part on oil quality, prices of competing fuels, distance to market, availability of infrastructure, the value of refined products, the supply/demand balance, other contractual terms and the world price for oil.

### *Natural Gas*

In Canada, the price of natural gas sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. The price received by a natural gas producer depends, in part, on the price of competing natural gas and other fuels, on natural gas quality, distance to market, access to downstream transportation, length of contract term, weather conditions, the supply/demand balance and other contractual terms. The government of Alberta also regulates the volume of natural gas which may be removed from the province for consumption elsewhere, based on such factors as reserve availability, transportation arrangements and other market conditions.

### *Natural Gas Liquids*

The price of condensate and other 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.

## Export from Canada

Crude oil, natural gas and NGLs exports from Canada are subject to the *National Energy Board Act* (Canada) (the "**NEB Act**") and the *National Energy Board Act Part VI (Oil and Gas) Regulation* (the "**Part VI Regulation**"). The NEB Act and the Part VI Regulation authorize crude oil, natural gas and NGLs exports under either short-term orders or long-term licences. To obtain a crude oil export licence, a mandatory public hearing with the National Energy Board (the "**NEB**") is required. There is no longer public hearing requirement for the export of natural gas and NGLs. Instead, the NEB uses a written process that includes a public comment period for impacted persons. Following the comment period, the NEB completes its assessment of the application and either approves or denies the application. For natural gas, the maximum duration of an export licence is 40 years and, for crude oil and other gas substances (e.g. NGLs), the maximum term is 25 years. In addition to NEB approval, all crude oil, natural gas and NGLs licences require the approval of the cabinet of the Canadian federal government ("**Cabinet**").

Orders from the NEB provide a short-term alternative to export licences and may be issued more expediently, since they do not require a public hearing or approval from Cabinet. Orders are issued pursuant to the Part VI Regulation for up to one or two years depending on the substance, with the exception of natural gas (other than NGLs) for which an order may be issued for up to twenty years for quantities not exceeding 30,000 m3 per day. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the NEB and the federal government. The Corporation does not directly enter into contracts to export its production outside of Canada.

On February 8, 2018, the Government of Canada introduced Bill C-69, draft legislation that, if enacted, will replace the NEB with the Canadian Energy Regulator ("**CER**"). The CER will take on the NEB's responsibilities with respect to the export of crude oil, natural gas and NGLs from Canada. However, it is not proposed that the legislative regime relating to exports of crude oil, natural gas and NGLs exports from Canada will substantively change under the new regime as currently drafted.

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 construction period 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**

Under the Canadian constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and require regulatory review and approval by Cabinet. However, recent years have seen a perceived lack of policy and regulatory certainty at a federal level. Although the current federal government introduced Bill C-69 to amend the federal approval processes, it is uncertain when the new legislation will be brought into force and whether any changes will be made to the draft legislation in the interim period. It is also uncertain whether any new approval process adopted by the federal government will result in a more efficient approval process. The lack of regulatory certainty is likely to have an influence on investment decisions for major projects. Even when projects are approved on a federal level, such projects often face further delays due to interference by provincial and municipal governments, as well as court challenges related to issues such as indigenous title, the government's duty to consult and accommodate indigenous peoples and the sufficiency of the relevant environmental review processes. Such political and legal opposition erodes confidence in the regulatory process. In addition, export pipelines from Canada to the United States face additional uncertainty 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 proposed 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 Expansion from Hardisty, Alberta, to Superior, Wisconsin, has an expected in-service date in the latter half of 2020.

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 Government's indigenous consultations. The Court quashed the accompanying certificate of public convenience and necessity and directed Cabinet to correct these deficiencies. Following the Court's direction, Cabinet ordered the NEB to reconsider its recommendation in light of the Federal Court of Appeal decision. On February 22, 2019, the NEB decided the Trans Mountain Pipeline expansion project was in the best interests of Canadians and should go forward subject to 156 conditions. The NEB also made 16 new recommendations to the Governor in Council. The Federal Government has announced the decision to approve or deny the Trans Mountain Pipeline expansion, subject to a new round of indigenous consultation, will be made by June 19, 2019.

While it was expected that construction on the Keystone XL Pipeline would commence in the first half of 2019, pre-construction work was halted in late 2018 when a U.S. Federal Court Judge determined the underlying environmental review was inadequate. On March 29, 2019 a new presidential permit was issued for the construction of the Keystone XL Pipeline.

Finally, Bill C-48 continues to advance through the federal legislative process. If enacted, Bill C-48 will impose a moratorium on tanker traffic transporting certain crude oil and NGLs products from British Columbia's north coast. See "Regulatory Authorities and Environmental Regulation" in these Industry Conditions.

On November 28, 2018, the Government of Alberta announced that Alberta has started negotiations for investment in new rail capacity to address the historically high price differential. Commencing in late 2019, the Government of Alberta intends to create enough new rail capacity to move 120,000 barrels a day out of the province. The Government expects that the railcar acquisition will narrow the oil price gap by up to $4 per barrel and will provide junior producers with a more affordable option to move their oil to market.

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 reduced capacity and apportionment of firm access, which in Western Canada may be further exacerbated by natural gas storage limitations. 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.

### Curtailment

On December 2, 2018, the Government of Alberta announced that, commencing January 1, 2019, it would mandate an 8.7% short-term reduction in provincial crude oil and crude bitumen production. As contemplated in the Curtailment Rules, the Government of Alberta will, on a monthly basis, direct oil producers producing more than 10,000 bbl/d to curtail their production according to a pre-determined formula that apportions production limits proportionately amongst those operators subject to a curtailment order. The first curtailment order took effect on January 1, 2019. The Government expects that the 8.7% curtailment rate will gradually drop over the course of 2019. Currently the Corporation is not subject to a curtailment order.

### The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada-United States Free Trade Agreement. Under the terms of NAFTA's Article 605, a proportionality clause prevents Canada from implementing policies that limit exports to the United States and Mexico, relative to the total supply produced in Canada. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not (i) reduce the proportion of energy resources exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price subject to an exception with respect to certain voluntary measures which only restrict the volume of exports; and (iii) disrupt normal channels of supply. NAFTA parties are generally prohibited from imposing minimum or maximum import and export price restrictions. However, import price restrictions are allowed to the extent that such restrictions are allowed by the anti-dumping and anti-subsidy provisions of the General Agreement on Tariffs and Trade.

On November 30, 2018, United States President Donald Trump, Prime Minister Justin Trudeau, and outgoing Mexican President Enrique Pena Nieto signed an authorization for a new trade deal that will replace NAFTA, referred to as the United States-Mexico-Canada Agreement ("**USMCA**"). However, NAFTA remains the North American trade agreement currently in force until the legislative bodies of the three signatory countries ratify the USMCA. Amid political uncertainty in Canada, Mexico, and the United States it is unclear when the end of the NAFTA era will be. As the United States remains by far Canada's largest trade partner and the largest international market for the export of crude oil, natural gas and NGLs from Canada the implementation of the final ratified version of the USMCA could have an impact on Western Canada's crude oil and natural gas industry at large, including the Corporation's business.

As discussed above, in December 2018 the Government of Alberta announced a curtailment of Alberta's crude oil and crude bitumen production for 2019. Curtailment complies with NAFTA's Article 605, under which Canada must make available a consistent proportion of the oil and bitumen produced to the other NAFTA signatories. As a result of the proportionality rule, reducing Canadian supply reduces the required offering under NAFTA, with the result that the amount of oil and bitumen that Canada is required to offer, while Canadian oil is at depressed prices, may be reduced. It is not clear whether the USMCA will come into force before the Government of Alberta's curtailment order is repealed automatically on December 31, 2019.

The USMCA does not contain the proportionality rules of NAFTA's Article 605. The elimination of the proportionality clause removes a barrier in Canada's transition to a more diversified export portfolio. While diversification depends on the construction of infrastructure allowing more Canadian production to reach Eastern Canada, Asia, and Europe, the USMCA may allow for greater export diversification than currently exists under NAFTA.

Canada has also pursued a number of other international free trade agreements with other countries around the world. As a result, a number of free trade or similar agreements are in force between Canada and certain other countries. 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 addition, Canada and ten other countries recently concluded discussions and agreed on the draft 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. On December 30, 2018 the CPTPP came into force among the first six countries to ratify the agreement – Canada, Australia, Japan, Mexico, New Zealand, and Singapore. While it is uncertain what effect CETA, CPTPP 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.

**Land Tenure**

Where mineral rights are owned by the government, rights are granted to energy companies to explore for and produce 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 oil or 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.

Oil and natural gas can also be privately owned (freehold) and rights to explore for and produce such 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.

In addition, the Federal government may from time to time provide incentives to the oil and gas industry. In November of 2018, the Federal government announced its plans to implement an accelerated investment incentive, which will provide oil and gas businesses with eligible Canadian development expenses and Canadian oil and gas property expenses with a first-year deduction of one and a half times the deduction that is otherwise available. The Federal government also announced in late 2018 that it will make $1.6 billion available to the oil and gas industry considering worsening commodity price differentials. The aid package, however, is mostly in the form of loans and is earmarked for oil and gas projects related to economic diversification as well as direct funding for clean growth oil and gas projects.

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 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.

Alberta has adopted a new, modernized Alberta royalty framework (the "**Modernized Framework**") that applies to all wells drilled after January 1, 2017. The previous royalty framework (the "**Old Framework**") will continue to apply to wells drilled prior to January 1, 2017 for a period of ten years ending on December 31, 2026. After the expiry of this ten-year period, these older wells will become subject to the Modernized Framework.

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

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

The Old Framework is applicable to all conventional 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 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.

*Incentive Programs*

Under the Modernized Framework, two strategic programs have been recently introduced with the intention of promoting expanded production potential and generating long-term returns to the Province of Alberta.

The new Enhanced Hydrocarbon Recovery Program (the "**EHR Program**") began on January 1, 2017 and replaced the existing EOR Program. The EHR Program is intended to promote incremental production through enhanced recovery methods and consists of two main components. The first component targets tertiary recovery schemes, which enhance recovery of hydrocarbons from an oil or gas pool by miscible flooding, immiscible flooding, solvent flooding, chemical flooding or other approved methods. The second component targets secondary recovery schemes, which enhance recovery of hydrocarbons from an oil or gas pool by water flooding, gas cycling, gas flooding, polymer flooding or other approved methods. Under both components of the program, a company pays a flat royalty of 5% on crude oil, natural gas and natural gas liquids produced from wells in an approved scheme for a limited benefit period. After the benefit period ends, wells in these schemes are subject to normal royalty rates under the Modernized Framework.

The new Emerging Resources Program (the "**ERP**") began January 1, 2017. The ERP is intended to encourage industry to open up new oil and gas resources in higher-risk and higher-cost areas that have large resource potential. For the purposes of the ERP, a project consists of a defined geographic area, target formation, set of wells and associated infrastructure. Wells that receive program benefits pay a flat royalty rate of 5% until their combined revenue equals their combined program specific cost allowances established under the ERP, which will replace the standard Drilling and Completion Cost Allowance under the Modernized Framework in respect of such wells. After achieving payout of the specific cost allowance, wells are subject to normal royalty rates under the Modernized Framework.

**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. 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 June 20, 2016, the federal government launched a review of current environmental and regulatory processes. On February 8, 2018, the Government of Canada introduced draft legislation to overhaul the existing environmental assessment process and replace the NEB with the CER. Pursuant to the draft legislation, the Impact Assessment Agency of Canada (the "**Agency**") would replace the Canadian Environmental Assessment Agency. Additional categories of projects may be included within new impact assessment process, such as largescale wind power facilities and in-situ oilsands facilities. The revamped approval process for applicable major developments will have specific legislated timelines at each stage of the formal impact assessment process. The Agency's process would focus on: (i) early engagement by proponents to engage the Agency and all stakeholders, such as the public and indigenous groups, prior to the formal impact assessment process; (ii) potentially increased public participation where the project undergoes a panel review; (iii) providing analysis of the potential impacts and effects of a project without making recommendations, to support a public-interest approach to decision-making, with cost benefit determinations and approvals made by the Minister of Environment and Climate Change or the cabinet of the federal government; (iv) analyzing further specified factors for projects such as alternatives to the project and social and indigenous issues in addition to health, environmental and economic impacts; and (v) overseeing an expanded follow-up, monitoring and enforcement process with increased involvement of indigenous peoples and communities. Many of the CER’s activities would be similar to the NEB, but with a different structure and the notable exception that the CER would no longer have primary responsibility in the consideration of the new major projects, instead focusing on the lifecycle regulation (e.g. overseeing construction, tolls and tariffs, operations and eventual winding down) of approved projects, while providing for expanded participation by communities and indigenous peoples. It is unclear when the new regulatory scheme will come into force or whether any amendments will be made prior to coming into force. Until then, the federal government's interim principles released on January 27, 2016 will continue to guide decision-making authorities for projects currently undergoing environmental assessment. The effect of the proposed regulatory scheme remains unclear.

On May 12, 2017, the federal government introduced Bill C-48, the Oil Tanker Moratorium Act, 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 is still considering the bill, which passed third reading on May 8, 2018. If implemented, the legislation may prevent the building of pipelines to, and export terminals located on, the portion of the British Columbia coast subject to the moratorium and, as a result, negatively affect the ability of producers to access global markets.

### *Alberta*

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.

## 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.

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.

In Redwater Energy Corporation (Re) ("**Redwater**"), the Court of Queen's Bench of Alberta found that there was an operational conflict between the abandonment and reclamation provisions of the provincial OGCA, including the AB LLR Program, and the federal Bankruptcy and Insolvency Act (the "BIA"). This ruling meant that receivers and trustees of insolvent entities have the right to renounce assets within insolvency proceedings and was affirmed by a majority of the Alberta Court of Appeal. On January 31, 2019, the Supreme Court of Canada overturned the lower courts' decisions, holding that there is no operational conflict between the abandonment and reclamation provisions contained in the provincial OGCA, the liability management regime administered by the AER and the federal bankruptcy and insolvency regime. As a result, receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets of a bankrupt licensee that have reached the end of their productive lives and represent a liability while dealing with the company’s valuable assets for the benefit of the company’s creditors without first satisfying abandonment and reclamation obligations.

In response to the lower courts’ decisions in Redwater, the AER issued several bulletins and interim rule changes to govern the AER's administration of its licensing and liability management programs pending a final decision from the Supreme Court of Canada. 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 are now assessed on a non-routine basis and the AER now requires all transferees to demonstrate that they have an LMR of 2.0 or higher immediately following the transfer, or to otherwise prove to the satisfaction of the AER that it can meet its abandonment and reclamation obligations. The AER may make further rule changes at any time. While the Supreme Court of Canada’s Redwater decision alleviates some of the concerns that the AER’s rule changes were intended to address, it is unclear how or if the AER will respond.

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. The list of current wells subject to the IWCP is available on the AER's Digital Data Submission system. The AER has announced that from April 1, 2015 to April 1, 2016, the number of noncompliant wells subject to the IWCP fell from 25,792 to 17,470, with 76% of licensees operating in the province having met their annual quota. From April 1, 2016 to April 1, 2017, this number fell from 17,470 to 12,375 noncompliant wells, with 81% of licensees operating in the province having met their annual quota. The IWCP completed its third year on March 31, 2018 but the AER has not yet released its third annual report.

**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 signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. As of January 1, 2019, 184 of the 197 parties to the convention have ratified the Paris Agreement. In December 2018, the United Nations annual Conference of the Parties took place in Katowice, Poland. The Conference concluded with the attendees reiterating their commitment to the targets set out in the Paris Agreement and establishing a transparency framework related to, among other matters, emissions and climate finance reporting.

Following the Paris Agreement and its ratification in Canada, the Government of Canada pledged to cut its emissions by 30% from 2005 levels by 2030. Further, on December 9, 2016, the Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change (the "**Framework**"). The Framework provided for a carbon-pricing strategy, with a carbon tax starting at $10/tonne, increasing annually until it reaches $50/tonne in 2022. A draft legislative proposal for the federal carbon pricing system was released on January 15, 2018. This system would apply in provinces and territories that request it and in those that do not have a carbon pricing system in place that meets the federal standards in 2018. Seven provinces and territories have introduced carbon pricing systems in place that would meet federal requirements (Alberta, British Columbia, Quebec, Prince Edward Island, Nova Scotia, Newfoundland and Labrador and the Northwest Territories). The federal carbon-pricing regime took effect in Saskatchewan, Manitoba, Ontario and New Brunswick on April 1, 2019; and will take effect in the Yukon, and Nunavut in July 2019. Saskatchewan and Ontario have challenged the constitutionality of the federal government's pricing regime; New Brunswick has intervened in Saskatchewan's constitutional challenge. In October 2018, the federal government announced an alternative pricing scheme for large electricity generators designed to incentivize a reduction in emissions intensity, rather than encouraging a reduction in generation rates.

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, but will not come into force until January 1, 2020. By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and intentional venting of methane, as well as ensuring that crude oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and gas facilities are permitted to vent. These facilities would need to capture the gas and either re-use it, re-inject it, send it to a sales pipeline, or route it to a flare. In addition, in provinces other than Alberta and British Columbia (which already regulate such activities), well completions by hydraulic fracturing would be required to conserve or destroy gas instead of venting. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

### *Alberta*

On November 22, 2015, the Government of Alberta introduced its Climate Leadership Plan (the "**CLP**"). The CLP has four areas of focus: implementing a carbon price on GHG emissions, phasing out coal-generated electricity and developing renewable energy, legislating an oil sands emission limit, and introducing a new methane emissions reduction plan. The Government of Alberta has since introduced new legislation to give effect to these initiatives. The Climate Leadership Act came into force on January 1, 2017 and enabled a carbon levy that increased from $20 to $30 per tonne on January 1, 2018. 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.

The *Carbon Competitiveness Incentives Regulation* (the "**CCIR**"), which replaces the *Specified Gas Emitters Regulation*, came into effect on January 1, 2018. Unlike the previous regulation, which set emission reduction requirements, the CCIR imposes an output-based benchmark on competitors in the same emitting industry. The aim is to reduce annual GHG emissions by 20 megatonnes by 2020 and 50 megatonnes by 2030, and targets facilities that emit more than 100,000 tonnes of GHGs per year and mandates quarterly and final reporting requirements. The CCIR compliance obligations will be reduced by 50% and 25% for 2018 and 2019, respectively, with no reduction for 2020 onward. In addition to the industry-specific benchmarks, each benchmark will decrease annually at a rate of 1%, beginning in 2020. The Government of Alberta intends for this strategy to align with the federal Framework.

The Government of Alberta also signaled its intention through its CLP to implement regulations that would lower annual methane emissions by 45% by 2025. Regulations are planned to take effect in 2020 to ensure the 2025 target is met.

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 over 15 years to fund two large-scale carbon capture and storage projects that will begin commercializing the technology on the scale needed to be successful. On December 2, 2010, the Government of Alberta passed the Carbon Capture and Storage Statutes Amendment Act, 2010. It deemed the pore space underlying all land in Alberta to be, and to have always been the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

The newly elected Premier of Alberta, sworn in April 30, 2019, has promised to repeal the Government of Alberta carbon levy, likely resulting in its replacement with the federal carbon-pricing regime, although the full effects of the anticipated repeal are unknown at this time.

### Accountability and Transparency

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.

## RISK FACTORS

An investment in the Corporation should be considered speculative due to the nature of the Corporation's involvement in the acquisition, exploration, development, production and marketing of oil and natural gas and due to its current stage of development. Oil and gas operations involve many risks which even a combination of experience and knowledge and careful project management may not be able to overcome. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Corporation or that existing oil and gas reserves owned by the Corporation can be profitably produced and sold.

### 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 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 oil and natural gas.

Future 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, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment and personal injury. Particularly, the Corporation may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation.

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

**Volatility of Oil and Gas Prices and General Economic Conditions**

The Corporation’s results of operations and financial condition are dependent on the prevailing prices of crude oil and natural gas. Crude oil and natural gas prices have fluctuated widely in the recent past and are subject to fluctuations in response to relatively minor changes in supply, demand, market uncertainty and other factors that are beyond the Corporation’s control. Crude oil and natural gas prices are affected by a number of factors including, but not limited to: the global and domestic supply of and demand for crude oil and natural gas; global and North American economic conditions; the actions of OPEC or individual producing nations; government regulation; political stability; the ability to transport commodities to markets; developments related to the market for liquefied natural gas; the availability and prices of alternate fuel sources; and weather conditions. In addition, significant growth in crude oil production in Western Canada and the northern United States has resulted in pressure on transportation and pipeline capacity, contributing to the widening of the light oil pricing differential between WTI and Canadian crude oil as well as contributing to fluctuations in the index price of oil and natural gas. All of these factors are beyond the Corporation’s control and can result in a high degree of price volatility.

Fluctuations in currency exchange rates further compound this volatility when the commodity prices, which are generally set in U.S. dollars, are stated in Canadian dollars. The Corporation's financial performance also depends on revenues from the sale of commodities which differ in quality and location from underlying commodity prices quoted on financial exchanges.

Fluctuations in the price of commodities and associated price differentials affect the value of the Corporation's assets, the Corporation's ability to maintain its business objectives and to fund growth. Prolonged periods of commodity price depression and volatility may also affect the Corporation's ability to meet guidance targets and meet all of its financial obligations as they come due. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Corporation's reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations, prospects and the level of expenditures for the development of oil and natural gas reserves, and may include delay or cancellation of existing or future drilling or development programs or curtailment in production.

Any material or sustained decline in commodity prices could result in a reduction of the Corporation's net production revenue and cash flows from operations. The economics of producing from some wells may change as a result of such lower prices, which could result in reduced production of oil or gas and a reduction in the volumes and value of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Corporation's expected net production revenue and cash flows from operations and a reduction in its oil and gas acquisition, development and exploration activities.

Crude oil and natural gas prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities as well as unforeseeable geopolitical events. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the economic return on acquisitions and development projects.

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

The Corporation conducts regular assessments of the carrying amount of its assets in accordance with IFRS. If crude oil and natural gas prices decline significantly and remain at low levels for an extended period of time, the carrying amount of the Corporation's assets may be subject to impairment.

**General Economic Conditions, Business Environment**

The business of the Corporation is subject to general economic conditions. Adverse changes in general economic and market conditions could negatively impact demand for crude oil and natural gas, revenues, operating costs, access to capital, timing and extent of capital expenditures, credit risk and counter party risk. There can be no assurance that any risk management steps taken by the Corporation, with the objective of the mitigating the foregoing risks, will avoid future loss due to the occurrence of such risks.

**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 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 Facility Risk**

The current Credit Facility is subject to review on May 31, 2020 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 Facility will not be renewed for the same amount or on the same terms or that the borrowing base will not be increased as a result of production growth to date and forecasted production growth. Although the Corporation believes that the Credit Facility will be sufficient for its immediate requirements, 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 Facility or from other sources on terms acceptable to the Corporation.

The Corporation is required to comply with its covenants under the Credit Facility. In the event that the Corporation does not comply with its covenants under the Credit Facility, access to the Credit Facility 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 oil and 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 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 federal government and the provincial governments of the Western Canadian provinces will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of the Corporation's projects. An increase in royalties would reduce the Corporation's earnings and could make future capital investments, or its operations, less economic. On January 29, 2016, the Government of Alberta adopted a new royalty regime which took effect on January 1, 2017. See "*Industry Conditions - Royalties and Incentives*".

**Hydraulic fracturing**

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

**Waterflood**

The Corporation undertakes 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 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 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 oil and natural gas include price, methods of delivery and reliability of delivery.

The marketability of 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. See "*Risk Factors – Environmental Concerns*".

**Operating Risks**

Oil and natural gas exploration is subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, oil spills and releases of possibly sour natural gas, each of which could result in substantial damage to oil and natural gas wells, producing facilities, other property and the environment or in personal injury and fatalities. In accordance with industry practice, the Corporation is not fully insured against all of these risks, nor are all such risks insurable or even identifiable. Although the Corporation maintains liability insurance in an amount which it considers adequate, the nature of these risks is such that liabilities could exceed policy limits, in which event the Corporation could incur significant costs that could have a materially adverse effect upon its financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs, the invasion of water into producing formations, inability to access production sites, access to third party pipelines and facilities, pipeline and facilities damage and a range of other risks, some of which may not be foreseeable. In addition, economic conditions may affect the solvency of suppliers, customers and partners, possibly resulting in financial loss and/or operational disruption.

**Availability of Equipment**

Oil and natural gas exploration and development activities are dependent on the availability of drilling, completion and related equipment as well as experienced and competent crews in the particular areas where such activities will be conducted. Demand for equipment or access restrictions may affect the availability of such equipment to the Corporation and may delay exploration and development activities. Further, to the extent the Corporation is not the operator of its oil and gas properties, the Corporation will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

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

**Environmental Concerns**

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.

**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.

**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 GHG 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 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 planned implementation of a nation-wide price on carbon emissions. The federal carbon levy goes into effect on April 1, 2019 and will affect provinces which have not implemented their own carbon taxes, cap-and-trade systems or other plans for carbon pricing, namely Ontario, Manitoba, Saskatchewan and New Brunswick. The federal carbon levy will be at an initial rate of $20 per tonne. Provincially, the Government of Alberta has already implemented a carbon levy on almost all sources of GHG emissions, now at a rate of $30 per tonne. The implementation of the federal carbon levy is currently subject to a constitutional challenge submitted by the Province of Saskatchewan, which is supported by the Provinces of Ontario and New Brunswick. 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*".

In addition, there has been public discussion that climate change may be associated with extreme weather conditions and increased volatility in seasonal temperatures. Extreme weather could interfere with the Corporation's production and increase Altura's costs. At this time, the Corporation is unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting its 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. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs*".

**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 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.

**Title Reviews**

Although title reviews will be completed according to industry standards prior to the purchase of most oil and natural gas properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the claim of the Corporation which could result in a reduction of the revenue received by the Corporation from exploitation of the property.

**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, 2018 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 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 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.

**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.

**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

Except for contracts entered into in the ordinary course of business, the only material contracts that the Corporation has entered into within the last financial year, or before the last financial year, which are still in effect and can reasonably be regarded as presently material, are the following:

1. the Agreement of Purchase and Sale (East Central Alberta and Saskatchewan) (see "*General Development of the Business – 2018*").

A copy of the foregoing may be viewed on the SEDAR website at www.sedar.com.

## 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 - 5$^{th}$ Avenue S.W., Calgary, Alberta, T2P 2V7.

The transfer agent and registrar for the Common Shares of the Corporation is Computershare 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, is contained in the Corporation's information circular dated April 9, 2019 relating to the annual general and special meeting of shareholders to be held on May 16, 2019.

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, 2018. 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, 2018. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2018 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 (the "**COGE Handbook**") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

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

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2018, and identifies the respective portions thereof that we have evaluated and reported on to the Company's Management:

**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 & Associates | December 31, 2018 | Canada | - | 116,621 | - | 116,621 |

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 reports 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)
M. J. Verney, P. Eng.
Executive Vice President

Calgary, Alberta, Canada
March 4, 2019

## 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, 2018 (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 29, 2019