ALTURA ENERGY INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2017

April 26, 2018

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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.

"**A&R**" means abandonment, reclamation and remediation;

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

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

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

"**Agency**" has the meaning ascribed thereto under the heading "*Industry Conditions – Canadian Environmental Regulation – Federal*";

"**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;

"**Bulletin 21**" has the meaning ascribed thereto under the heading "*Industry Conditions – Abandonment and Reclamation Cost Risk*";

"**CCIR**" has the meaning ascribed thereto under the heading "*Industry Conditions – Canadian Environmental Regulation – Alberta*";

"**CER**" means the Canadian Energy Regulator;

"**CLA**" has the meaning ascribed thereto under the heading "*Industry Conditions – Canadian Environmental Regulation – Alberta*";

"**CL Regulation**" has the meaning ascribed thereto under the heading "*Industry Conditions – Canadian Environmental Regulation – Alberta*";

"**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;

"**Consolidation**" has the meaning ascribed thereto under the heading "*General Development of the Business – 2015*";

"**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;

"**Directive 013**" has the meaning ascribed thereto under the heading "*Industry Conditions – Abandonment and Reclamation Cost Risk*";

"**EHR Program**" has the meaning ascribed thereto under the heading "*Industry Conditions – Royalties and Incentives – Alberta*";

"**ERP**" has the meaning ascribed thereto under the heading "*Industry Conditions – Royalties and Incentives – Alberta*";

"**ESTMA**" has the meaning ascribed thereto under the heading "*Industry Conditions – Accountability and Transparency*";

"**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;

"**IWCP**" has the meaning ascribed thereto under the heading "*Industry Conditions – Abandonment and Reclamation Cost Risk*";

"**LMR**" means liability management rating;

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

"**McDaniel Report**" means the report prepared by McDaniel, in accordance with NI 51-101, dated February 21, 2018 and effective December 31, 2017;

"**Modernized Framework**" has the meaning ascribed thereto under the heading "*Industry Conditions – Royalties and Incentives – Alberta*";

"**NAFTA**" means the North American Free Trade Agreement;

"**NEB**" means the National Energy Board;

"**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;

"**New Directors**" means Darren Gee, Brian Lavergne, Robert Maitland, John McAleer and David Burghardt;

"**New Management Team**" means David Burghardt, President & Chief Executive Officer of the Corporation, Travis Stephenson, Vice President, Engineering of the Corporation, Robert Pinckston, Vice President, Exploration of the Corporation of the Corporation and Jeff Mazurak, Vice President, Operations of the Corporation;

"**NCIB**" has the meaning ascribed thereto under the heading "*General Development of the Business – 2015*";

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

"**Old Framework**" has the meaning ascribed thereto under the heading "*Industry Conditions – Royalties and Incentives – Alberta*";

"**Options**" means options to purchase Common Shares granted under the Corporation's stock option plan;

"**OWA**" means the Orphan Well Association;

"**Paris Agreement**" has the meaning ascribed thereto under the heading "*Industry Conditions – Canadian Environmental Regulation – Federal*";

"**Performance Warrant**" has the meaning ascribed thereto under the heading "*General Development of the Business – 2015*";

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

"**Private Placement**" has the meaning ascribed thereto under the heading "*General Development of the Business – 2015*";

"**PSA**" has the meaning ascribed thereto under the heading "*Industry Conditions – Canadian Environmental Regulation – Federal*";

"**Redwater**" has the meaning ascribed thereto under the heading "*Industry Conditions – Abandonment and Reclamation Cost Risk*";

"**Reorganization and Investment Agreement**" means the reorganization and investment agreement dated July 6, 2015 between the Corporation and the New Management Team which provided for: (i) a non-brokered private placement of an aggregate minimum of approximately $20 million and up to an aggregate maximum of approximately $25 million; (ii) the appointment of a new management team and new directors; and (iii) the Rights Offering;

"**Rights Offering**" has the meaning ascribed thereto under the heading "*General Development of the Business – 2015*";

"**RLI**" means Reserve Life Index;

"**SGER**" has the meaning ascribed thereto under the heading "*Industry Conditions – Canadian Environmental Regulation – Alberta*";

"**SGRR**" has the meaning ascribed thereto under the heading "*Industry Conditions – Canadian Environmental Regulation – Alberta*";

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

"**Unit**" has the meaning ascribed thereto under the heading "*General Development of the Business – 2015*"; and

"**UNFCCC**" means the United Nations Framework Convention on Climate Change;

"**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, 2017 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
GHG	greenhouse gas
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

Oil and Gas Metrics

This AIF contains metrics commonly used in the oil and natural gas industry, such as "finding development and acquisition costs" or "FD&A costs", "recycle ratio", "reserve replacement", "reserve life index" and "operating netbacks". These oil and gas metrics have been prepared by management and do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included in this AIF to provide readers with additional measures to evaluate Altura's performance, however, such measures are not reliable indicators of future performance and future performance may not compare to the Corporation's performance in previous periods and therefore such metrics should not be unduly relied upon. Management uses these oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare Altura's operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this AIF, should not be relied upon for investment or other purposes. Specifically, this AIF contains the following metrics:

Finding, Development and Acquisition costs ("FD&A costs")

FD&A costs are calculated by dividing the sum of the total capital expenditures for the year inclusive of the net acquisition costs and disposition proceeds (in dollars) by the change in reserves within the applicable reserves category inclusive of changes due to acquisitions and dispositions (in Boe). FD&A costs include all capital expenditures in the year inclusive of the net acquisition costs and disposition proceeds as well as the change in estimated future development costs required to bring the reserves within the specified reserves category on production.

FD&A costs take into account reserves revisions and capital revisions during the year. The aggregate of the costs incurred in the financial year and changes during that year in estimated future development costs may not reflect total finding and development costs related to reserves additions for that year. FD&A costs have been presented in this AIF because acquisitions and dispositions can have a significant impact on Altura's ongoing reserves replacement costs and excluding these amounts could result in an inaccurate portrayal of its cost structure. Management uses FD&A costs as a measure of its ability to execute its capital programs (and success in doing so) and of its asset quality.

The aggregate of the development and exploration costs incurred in the financial year and changes during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

Recycle Ratio

Recycle ratio is calculated by dividing the operating netback (in dollars per Boe) by the FD&A costs (in dollars per Boe) for the year. Altura uses recycle ratio as an indicator of profitability of its oil and gas activities.

Reserve Replacement

Reserve replacement is calculated by dividing the annual change in reserves before production (in Boe) in the referenced category by Altura's annual production (in Boe). Management uses this measure to determine the relative change of its reserves base over a period of time.

Reserve Life Index

RLI is calculated by dividing the reserves (in Boe) in the referenced category by the fourth quarter of 2017 production volumes (in Boe). Management uses this measure to determine how long the booked reserves will last at current production rates if no further reserves were added.

Operating Netback

Operating netback does not have a standardized meaning as prescribed by generally accepted accounting principles codified by IFRS. Operating netback is calculated using production revenues, less royalties, transportation and operating expenses, calculated on a per Boe equivalent basis. Management believes that in addition to net income, netbacks are a useful supplemental measure as it assists in the determination of the Corporation's operating performance between areas and/or time periods. Readers should be cautioned, however, that this measure should not be construed as an alternative to both net income and net cash from (used in) operating activities, which are determined in accordance with IFRS, as an indicator of the Corporation's performance.

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;
- 2018 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." and to effect the Consolidation. See "*General Development of the Business*".

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 4300 Bankers Hall West, 888 – 3rd Street S.W., Calgary, Alberta, T2P 5C5, and its head and principal office is located at 200, 640 – 5th Avenue S.W., Calgary, Alberta, T2P 3G4.

Note on Share References

On October 16, 2015, Altura effected the Consolidation on the basis of one post-Consolidation Common Share for every ten pre-Consolidation Common Shares. Unless otherwise noted, all references to Common Shares are on a post-Consolidation basis.

GENERAL DEVELOPMENT OF THE BUSINESS

From January 1, 2015 to December 31, 2017 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.

2015

Overview of Capital Expenditure Program

During the year ended December 31, 2015, the Corporation executed a $3.0 million capital program and drilled one gross (1.0 net) well in the Eyehill area of Alberta. Additionally, the Corporation acquired freehold and Crown leases in 16 sections of land in the Leduc-Woodbend area of Alberta and eight sections of Crown leases in the Provost area of Alberta. Average production for the year was 361 Boe/d.

General Business Developments

The Corporation purchased a total of 624,200 Common Shares for cancellation at a weighted average price of $0.46 per share between February 22, 2015 and June 23, 2015, pursuant to the Corporation's normal course issuer bid ("**NCIB**") to purchase for cancellation up to 2,315,134 Common Shares during the period from December 24, 2014 to December 24, 2015. The Corporation did not purchase for cancellation any additional Common Shares between June 24, 2015 and the expiry of the NCIB on December 24, 2015.

On May 25, 2015, the Credit Facility with a Canadian Chartered Bank was increased from $5.0 million to $6.5 million.

In the second quarter of 2015, the Corporation acquired increased working interests of non-producing properties in the Wildmere area of Alberta for cash consideration of $0.3 million.

Pursuant to the Reorganization and Investment Agreement, the Corporation completed a non-brokered private placement (the "**Private Placement**") (i) the first tranche of which closed on July 31, 2015, whereby the Corporation issued an aggregate of 601,594,612 pre-Consolidation Common Shares at a price of $0.03375 per Common Share and 98,740,741 units of the Corporation ("**Units**") at a price of $0.03375 per Unit, (ii) the second tranche of which closed on August 28, 2015, whereby the Corporation issued an aggregate of 18,885,089 pre-Consolidation Common Shares at a price of $0.03375 per Common Share and 3,498,785 Units at a price of $0.03375 per Unit, and (iii) the third tranche of which closed on September 4, 2015, whereby the Corporation issued an aggregate of 6,755,555 pre-Consolidation Common Shares at a price of $0.03375 per Common Share for total gross proceeds of $24.62 million. Each Unit consists of one pre-Consolidation Common Share and one Common Share purchase performance warrant ("**Performance Warrant**") entitling the holder to acquire one pre-Consolidation Common Share at an exercise price of $0.0449 per Common Share within five years from the date of issuance with one-third vesting each upon the occurrence of the 20-day weighted average trading price of the pre-Consolidation Common Shares equaling or exceeding $0.0675, $0.0901 and $0.1124, respectively.

Contemporaneous with the closing of the first tranche of the Private Placement on July 31, 2015, the appointments of the New Management Team and the New Directors were completed. Effective September 1, 2015, the Corporation appointed Tavis Carlson as Vice-President, Finance & Chief Financial Officer and Secretary.

On August 26, 2015, the Corporation commenced a rights offering (the "**Rights Offering**") by way of a rights offering circular which was mailed to each shareholder of record on September 8, 2015 (the "**Record Date**"). Pursuant to the Rights Offering, each shareholder was issued one right ("**Right**") for each pre-Consolidation Common Share held as of the Record Date, entitling that holder to purchase one pre-Consolidation Common Share for each nine Rights held at an exercise price of $0.03375 per Common Share.

At a special meeting of the shareholders of the Corporation on September 30, 2015, the shareholders of the Corporation approved (i) a change of the Corporation's name to "Altura Energy Inc.", (ii) an initial consolidation of the Common Shares on the basis of one new Common Share for every ten existing Common Shares (the "**Consolidation**") and a possible second consolidation on the basis of one new Common Share for every four Common Shares issued and outstanding following completion of the Consolidation, for a combined share consolidation of 40:1, and (iii) the amendment of the Corporation's articles to explicitly stipulate that the Corporation is authorized to issue an unlimited number of Common Shares and an unlimited number of Preferred Shares. The second consolidation of one new Common Share for every four Common shares has yet to be effected.

On October 9, 2015, the Corporation completed the Rights Offering pursuant to which shareholders subscribed for and purchased an aggregate of 10,201,249 pre-Consolidation Common Shares at a price of $0.03375 per Common Share for gross proceeds of approximately $0.34 million.

On October 16, 2015, the Corporation's name was changed from "Northern Spirit Resources Inc." to "Altura Energy Inc." and the articles of the Corporation were also amended to effect the Consolidation.

On October 19, 2015, the Corporation's Common Shares commenced trading on the TSXV under the new symbol "ATU".

On November 23, 2015, the Board of Directors approved a capital development budget ranging between $5.0 and $11.0 million for 2016, funded with cash flow from operating activities and working capital. The budget included drilling up to seven gross (6.4 net) horizontal wells targeting the Upper Mannville Formation.

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.

Recent Developments

On March 22, 2018, the Corporation confirmed its 2018 capital budget to be $15.0 million.

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, east central Alberta and Saskatchewan. Altura seeks to identify and acquire strategic oil and gas properties where it believes further exploitation, development and exploration opportunities exist.

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.

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 100% working interest in 41,400 net acres of land in the Leduc-Woodbend area, of which 39,954 net acres are undeveloped and 1,146 net acres are developed. Altura drilled three wells in the area in 2017, of which one was brought on production in the second quarter of 2017 and two were brought on production in the fourth quarter of 2017. The Corporation's exploration, development and production activities in the Leduc-Woodbend area are directed towards 17° API oil in the Upper Mannville Formation.

McDaniel assigned approximately 1,221.3 Mboe of proved reserves and 2,139.8 Mboe of proved plus probable reserves in the Leduc-Woodbend area in the McDaniel Report.

During the year ended December 31, 2017, Altura had average production of approximately 253 Boe/d (including 228 Bbls/d of oil and liquids and 150 Mcf/d of natural gas) from four gross (4.0 net) producing wells in the area. Production in the area is tied into two batteries owned and operated by the Corporation. Oil sales volumes are trucked to a sales point and natural gas production is transported via pipeline and processed by two third party operators.

Eyehill Area (Formerly Klein North)

The Eyehill area of east central Alberta is located approximately 20 kilometers south of Provost, Alberta. Altura currently holds a 100% working interest in 1,280 acres of land in the Eyehill area, of which 640 acres are undeveloped and 640 acres are developed. Altura acquired its assets in the Eyehill area through Crown land sales. Altura drilled three wells in the area in 2017, which were brought on production in the second quarter of 2017. The Corporation's exploration, development and production activities in the Eyehill area are directed towards 28° API oil in the Sparky Formation.

McDaniel assigned approximately 863.8 Mboe of proved reserves and 1,349.9 Mboe of proved plus probable reserves in the Eyehill area in the McDaniel Report.

During the year ended December 31, 2017, Altura had average production of approximately 536 Boe/d (including 454 Bbls/d of oil and liquids and 493 Mcf/d of natural gas) from ten gross (10.0 net) producing wells in the Eyehill area. All production in the area is tied into a multi-well battery owned and operated by the Corporation. Oil sales volumes are trucked to a sales point and natural gas production is transported via pipeline and processed by a third party.

In August 2017 Altura converted a producing one-mile horizontal well to a water injection well and commenced a waterflood pilot project.

Eyehill South Area (Formerly Klein South)

The Eyehill South area of east central Alberta is located approximately 28 kilometers south of Provost, Alberta. Altura currently holds a 76% working interest in 2,080 gross (1,578 net) acres of land in the Eyehill South area, of which 160 gross (160 net) acres are undeveloped and 1,920 gross (1,418 net) acres are developed. The Corporation's exploration, development and production activities in the Eyehill South area are directed towards 28° API oil in the Sparky Formation.

McDaniel assigned approximately 55.1 Mboe of proved reserves and 106.6 Mboe of proved plus probable reserves in the Eyehill South area in the McDaniel Report.

During the year ended December 31, 2017, Altura had average production of approximately 24 Bbls/d (100% crude oil) from four gross (2.2 net) producing wells in the Eyehill South area. All production in the area is treated on site and tied into single well batteries owned and operated by the Corporation. Oil sales volumes are trucked to a sales point.

Macklin Area

The Macklin area is located on the Alberta/Saskatchewan border, approximately 10 kilometers north of Macklin, Saskatchewan. Altura currently holds a 100% working interest in 6,388 net acres of land in the Macklin area, of which 4,783 net acres are undeveloped and 1,604 net acres are developed. Altura drilled one well in the area in 2017 which was brought on production in the second quarter of 2017. The Corporation's exploration, development and production activities in the Macklin area is directed towards 19° API oil in the Sparky Formation.

McDaniel assigned approximately 147.7 Mboe of proved reserves and 557.3 Mboe of proved plus probable reserves in the Macklin area in the McDaniel Report.

During the year ended December 31, 2017, Altura had average production of approximately 36 Bbls/d (100% crude oil) from one gross (1.0 net) producing well in the Macklin area. The well is tied into a single well battery owned and operated by the Corporation. Oil sales volumes are trucked to a sales point.

Killam Area

The Killam area of east central Alberta is located approximately 65 kilometers west of Wainwright, Alberta. Altura holds an 87.6% working interest in 3,872 gross (3,393 net) acres of land in the Killam area, of which 480 gross (480 net) acres are undeveloped and 3,392 gross (2,913 net) acres are developed. Altura drilled one gross (1.0 net) well at Killam in the first quarter of 2017, which was brought on production in the second quarter of 2017. The Corporation's exploration, development and production activities in the Killam area are directed towards 28° API oil in the Upper Mannville Formation.

McDaniel assigned approximately 555.4 Mboe of proved reserves and 740.0 Mboe of proved plus probable reserves in the Killam area in the McDaniel Report.

During the year ended December 31, 2017, Altura had average production of approximately 131 Boe/d (including 74 Bbls/d of oil and liquids and 339 Mcf/d of natural gas) from ten gross (10.0 net) producing wells in the area. All production in the area is tied into two multi-well batteries owned and operated by the Corporation. Oil sales volumes are trucked to a sales point and natural gas production is transported via pipeline and processed by a third party.

Wildmere Area

The Wildmere area of east central Alberta is located approximately 40 kilometers north of Wainwright, Alberta. Altura currently holds an average working interest of 62% working interest in 2,240 gross (1,388 net) acres of land in the Wildmere area, of which 440 gross (284 net) acres are undeveloped and 1,800 gross (1,104 net) acres are developed. The Corporation's exploration, development and production activities in the Wildmere area are directed towards 15° API oil in the Sparky Formation.

McDaniel assigned approximately 227.9 Mboe of proved reserves and 428.1 Mboe of proved plus probable reserves in the Wildmere area in the McDaniel Report.

During the year ended December 31, 2017, Altura had average production of approximately 72 Bbls/d (100% crude oil) from three gross (2.5 net) producing wells in the Wildmere area. All production in the area is tied into and treated at a multi-well battery owned and operated by the Corporation. Oil sales volumes are trucked to a sales point.

Employees

As at December 31, 2017, the Corporation employed seven full-time employees located at the head office. The Corporation also retained six consultants, two of which are located at the head office and four 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, 2017 and a preparation date of February 21, 2018. 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 Provinces of Alberta and Saskatchewan.

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, 2017 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, 2017
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	729.8	665.4	458.6	418.7	2,183.2	1,983.9	42.3	34.7
Non-Producing	114.9	70.4	-	-	(98.5)	(99.4)	(1.8)	(1.6)
Undeveloped	294.8	261.0	825.4	759.7	1,538.4	1,385.7	39.6	35.2
Total Proved	**1,139.4**	**996.8**	**1,284.1**	**1,178.4**	**3,623.2**	**3,270.2**	**80.1**	**68.3**
Total Probable	588.1	510.4	1,288.8	1,179.3	1,986.7	1,800.9	54.5	44.9
Total Proved & Probable	**1,727.5**	**1,507.2**	**2,572.9**	**2,357.7**	**5,609.8**	**5,071.1**	**134.5**	**113.3**

(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, 2017
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	37,928	32,795	28,832	25,765	23,355	37,928	32,795	28,832	25,765	23,355	19.89
Non-Producing	3,953	3,494	3,068	2,700	2,390	3,069	2,897	2,655	2,408	2,180	58.72
Undeveloped	21,193	14,965	10,434	7,126	4,675	15,051	10,213	6,653	4,048	2,123	8.11
Total Proved	**63,074**	**51,254**	**42,334**	**35,590**	**30,420**	**56,049**	**45,905**	**38,140**	**32,221**	**27,658**	**15.18**
Total Probable	67,600	46,505	33,725	25,557	20,053	49,738	33,917	24,295	18,163	14,053	16.57
Total Proved & Probable	**130,675**	**97,759**	**76,059**	**61,148**	**50,473**	**105,787**	**79,823**	**62,435**	**50,384**	**41,711**	**15.77**

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

Total Future Net Revenue (Undiscounted)
Forecast Prices and Costs as of December 31, 2017
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	170,910	17,724	59,776	25,806	4,530	63,074	7,026	56,049
Total Proved & Probable Reserves	315,001	32,507	105,567	40,151	6,101	130,675	24,888	105,787

(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, 2017
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)	25,188	25.27
	Heavy Oil (Including Solution Gas and By-products)	17,185	14.58
	Conventional Natural Gas (Including By-products)	(38)	(1.05)
	Total	**42,334**	
Total Proved & Probable Reserves	Light and Medium Oil (Including Solution Gas and By-products)	36,713	24.36
	Heavy Oil (Including Solution Gas and By-products)	39,376	16.70
	Conventional Natural Gas (Including By-products)	(29)	(0.57)
	Total	**76,059**	

(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, 2017, were $51.41/Bbl for light and medium oil, $46.75/Bbl for heavy oil, $2.33/Mcf for natural gas and $42.79/Bbl for NGLs. McDaniel employed the following pricing, exchange rate and inflation rate assumptions as of December 31, 2017 in the McDaniel Report in estimating reserves data using forecast prices and costs. Benchmark weighted average historical prices for 2017 are also reflected in the tables below.

McDaniel & Associates Consultants Ltd.

Summary of Crude Oil and Natural Gas Liquids Price Forecasts

January 1, 2018

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													
2017	50.90	54.25	62.35	50.95	49.70	44.35	59.50	66.55	NA	28.90	44.65		0.770
Forecast													
2018	58.50	63.50	70.10	52.60	51.90	45.20	65.20	73.10	8.20	40.60	51.40	0.0	0.790
2019	58.70	61.30	71.30	57.80	57.00	49.60	66.30	74.40	9.80	38.10	52.20	2.0	0.790
2020	62.40	63.40	74.90	62.20	61.40	53.60	69.70	78.00	11.40	33.20	54.90	2.0	0.800
2021	69.00	70.10	80.50	66.80	66.00	57.60	74.90	83.70	12.80	34.30	59.00	2.0	0.825
2022	73.10	74.20	82.80	68.70	67.90	59.20	77.00	86.00	13.60	32.10	60.70	2.0	0.850
2023	74.50	75.60	84.40	70.10	69.20	60.30	78.50	87.70	13.80	31.00	61.80	2.0	0.850
2024	76.00	77.10	86.10	71.50	70.60	61.60	80.10	89.50	14.00	31.60	63.10	2.0	0.850
2025	77.50	78.60	87.80	72.90	72.00	62.80	81.70	91.20	14.20	32.20	64.30	2.0	0.850
2026	79.10	80.30	89.60	74.40	73.50	64.10	83.30	93.10	14.60	32.90	65.60	2.0	0.850
2027	80.70	81.90	91.40	75.90	74.90	65.40	85.00	95.00	14.80	33.50	67.00	2.0	0.850
2028	82.30	83.50	93.20	77.40	76.40	66.60	86.70	96.90	15.20	34.20	68.30	2.0	0.850
2029	83.90	85.10	95.00	78.90	77.90	67.90	88.40	98.70	15.60	34.90	69.60	2.0	0.850
2030	85.60	86.90	97.00	80.50	79.50	69.40	90.20	100.80	16.00	35.70	71.10	2.0	0.850
2031	87.30	88.60	98.90	82.10	81.10	70.70	92.00	102.80	16.20	36.30	72.50	2.0	0.850
2032	89.10	90.40	100.90	83.70	82.70	72.10	93.80	104.90	16.40	37.00	73.90	2.0	0.850
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	0.850

(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

McDaniel & Associates Consultants Ltd.

Summary of Natural Gas Price Forecasts

January 1, 2018

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	Alberta Spot Sales Plantgate $C/MMBtu	Sask. Prov. Gas Plantgate $C/MMBtu	British Columbia Average Plantgate $C/MMBtu	British Columbia Station 2 $C/MMBtu
History								
2017	2.95	2.40	2.15	2.15	2.15	2.35	1.75	1.88
Forecast								
2018	3.00	2.25	2.05	2.05	2.05	2.15	1.65	1.78
2019	3.05	2.65	2.45	2.45	2.45	2.55	2.15	2.28
2020	3.25	3.05	2.85	2.85	2.85	2.95	2.55	2.69
2021	3.55	3.40	3.20	3.20	3.20	3.30	3.00	3.14
2022	3.80	3.60	3.40	3.40	3.40	3.50	3.20	3.34
2023	3.85	3.65	3.45	3.45	3.45	3.55	3.25	3.39
2024	3.95	3.75	3.50	3.50	3.50	3.60	3.25	3.40
2025	4.00	3.80	3.55	3.55	3.55	3.65	3.30	3.45
2026	4.10	3.90	3.65	3.65	3.65	3.75	3.40	3.55
2027	4.15	3.95	3.70	3.70	3.70	3.80	3.45	3.61
2028	4.25	4.05	3.80	3.80	3.80	3.90	3.55	3.71
2029	4.35	4.15	3.90	3.90	3.90	4.00	3.65	3.81
2030	4.45	4.25	4.00	4.00	4.00	4.15	3.75	3.91
2031	4.50	4.30	4.05	4.05	4.05	4.20	3.80	3.97
2032	4.60	4.35	4.10	4.10	4.10	4.25	3.85	4.02
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, 2017, derived from the McDaniel Report using forecast prices and cost estimates, reconciled to the Corporation's gross reserves as at December 31, 2016.

Reconciliation of Company Gross Reserves by Product Type
Forecast Prices and Costs as of December 31, 2017
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, 2016	1,168.0	823.4	1,991.4	288.9	343.4	632.2	2,079.5	1,144.1	3,223.6
Extensions & Improved Recovery	-	-	-	1,095.7	942.1	2,037.8	1,548.5	926.4	2,474.9
Technical Revisions	181.6	(230.6)	(49.0)	34.1	3.3	37.4	404.9	(79.1)	325.8
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	(6.9)	(4.8)	(11.7)	-	-	-	(13.6)	(4.8)	(18.3)
Economic Factors	-	-	-	-	-	-	-	-	-
Production*	(203.2)	-	(203.2)	(134.5)	-	(134.5)	(396.2)	-	(396.2)
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

	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, 2016	18.0	16.3	34.3	1,821.4	1,373.8	3,195.2
Extensions & Improved Recovery	58.3	35.3	93.6	1,412.1	1,131.8	2,543.9
Technical Revisions	11.7	2.9	14.7	294.9	(237.5)	57.4
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	(0.1)	(0.1)	(0.2)	(9.3)	(5.6)	(14.9)
Economic Factors	-	-	-	-	-	-
Production	(7.9)	-	(7.9)	(411.7)	-	(411.7)
December 31, 2017	80.1	54.5	134.5	3,107.4	2,262.5	5,369.9

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 generally those reserves related to infill wells that have not yet been drilled or wells further away from gathering systems requiring relatively high capital to bring on production. Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. This also includes the probable undeveloped wedge from the proved undeveloped locations.

Altura currently plans to pursue the development of its proved and probable undeveloped reserves within the next two years through ordinary course capital expenditures. In some cases, it will take longer than two years to develop these reserves; however, the Corporation expects that the large majority of its booked undeveloped projects will be completed within a two-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.

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
2015	184.7	184.7	83.7	83.7	122.4	122.4	2.2	2.2
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

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 1,416.3 Mboe of proved undeveloped reserves in the McDaniel Report with $25.8 million of associated undiscounted capital, of which $21.1 million is forecast to be spent in the first two years.

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
2015	342.1	342.1	125.2	125.2	230.0	230.0	4.1	4.1
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

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 1,699.9 Mboe of probable undeveloped reserves in the McDaniel Report with $14.3 million of associated undiscounted capital, of which $6.3 million is forecast to be spent in the first two years.

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

Abandonment and reclamation costs have been estimated in the McDaniel Report and attributed to all properties that have been assigned reserves in the McDaniel Report and have been taken into account by McDaniel in determining reserves that should be attributed to a property and in determining the aggregated future net revenue therefrom. No allowance was made for the abandonment and reclamation of any pipelines or facilities.

Altura will be liable for its share of ongoing environmental obligations and for the ultimate reclamation of the surface leases, wells, facilities, and pipelines held by it upon abandonment. Ongoing environmental obligations are expected to be funded out of cash flow.

No estimate of salvage value is netted against the estimated cost. The Corporation's model for estimating the amount of future abandonment and reclamation expenditures was done on an individual well and facility level. Estimated expenditures for each well and facility are based on internal estimates using public data and management's experience. Each well and facility is assigned an average cost (by commodity type and well depth) for abandonment and reclamation. The estimated expenditures are based on current regulatory standards and actual abandonment cost history. Timing of expenditures is based on expected well lives.

The Corporation estimates that it will incur total net reclamation and abandonment costs of $6.6 million, undiscounted and un-escalated, to abandon and reclaim all wells and facilities. Abandonment and reclamation costs undiscounted and expected to be paid over the next three years totals approximately $1.4 million.

Additional information related to the Corporation's estimated share of future environmental and reclamation obligations for the working interest properties (including all abandonment and reclamation costs associated with all existing wells, facilities, pipelines and leases) can be found in Altura's audited consolidated financial statements for the year ended December 31, 2017 and the accompanying management's discussion and analysis, which are available on SEDAR at www.sedar.com.

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**
2018	7,082	11,032
2019	14,035	16,407
2020	4,689	12,711
2021	-	-
2022	-	-
Thereafter	-	-
Total for all years undiscounted	25,806	40,150
Total for all years discounted at 10% per year	22,701	34,779

Altura expects to use a combination of internally generated cash from operations, 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.

Oil and Gas Metrics

The following table highlights Altura's FD&A costs, recycle ratio, reserve replacement and reserve life index for 2017 and 2016.

	2017	**2016**
Total capital expenditures, acquisitions and dispositions ($000)	21,187	17,494
Change in future development costs – Total Proved ($000)	16,109	5,704
Change in future development costs – Total Proved + Probable ($000)	23,329	7,664
Q4 production (Boe/d)	1,202	988
Q4 operating netback ($/Boe)(1)	29.39	30.02
Annual operating netback ($/Boe) (1)	27.49	25.30
Proved Developed Producing		
FD&A costs ($/Boe) (1)	23.36	19.99
Recycle ratio(1) (Q4 operating netback)	1.3	1.5
Recycle ratio(1) (annual operating netback)	1.2	1.3
Reserve replacement(1)	220%	417%
RLI (years) (1)	3.6	3.0
Total Proved		
FD&A costs ($/Boe) (1)	21.97	17.76
Recycle ratio(1) (Q4 operating netback)	1.3	1.7
Recycle ratio(1) (annual operating netback)	1.3	1.4
Reserve replacement(1)	412%	622%
RLI (years)(1)	7.0	5.0
Total Proved + Probable		
FD&A costs ($/Boe) (1)	17.21	12.32
Recycle ratio(1) (Q4 operating netback)	1.7	2.4
Recycle ratio(1) (annual operating netback)	1.6	2.1
Reserve replacement(1)	628%	973%
RLI (years)(1)	12.1	8.8

Notes:

(1) "Operating netback", "FD&A costs", "Recycle ratio", "Reserve replacement" and "RLI" do not have standardized meanings. See "*Oil and Gas Advisories*" contained in this AIF.

OTHER OIL AND NATURAL GAS INFORMATION

Oil and Natural Gas Wells

The following table sets forth the number and status of the Corporation's wells effective December 31, 2017.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	29	26.7	22	20.6	3	3.0	33	23.2
Saskatchewan	1	1.0	1	1.0	0	0	0	0
Total	30	27.7	23	21.6	3	3.0	33	22.3

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, no wells were drilled in 2017 that were capable of production and had reserves assigned to them.

Properties with no Attributed Reserves

The following table summarizes, effective December 31, 2017, 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	60,359	59,711	2,373
Total	60,359	59,711	2,373

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 2019. 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, 2017.

	Property Acquisitions			
($000s)	**Proved Properties**	**Unproved Properties**	**Exploration Costs**	**Development Costs**
Total	-	-	1,876	20,426

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, 2017. All wells were drilled in Canada.

	Exploratory Wells		**Development Wells**	
	Gross	**Net**	**Gross**	**Net**
Crude Oil	-	-	8	8.0
Natural Gas	-	-	-	-
Service	-	-	-	-
Stratigraphic Test	-	-	-	-
Dry	-	-	-	-
Total	-	-	8	8.0

Planned Capital Expenditures

In December 2017, Altura announced its preliminary capital expenditure budget of $15.0 million for 2018, which was confirmed on March 22, 2018. The capital development budget is split approximately 60% to drilling, completion, equipping and tie-in capital and 40% to infrastructure and other capital. The budget includes three gross (3.0 net) extended reach horizontal wells targeting the Upper Mannville Group at Leduc-Woodbend and one gross (1.0 net) horizontal well targeting the Sparky Formation at Macklin.

With the current volatility of commodity prices and Canadian oil differentials, Altura continues to actively monitor the 2018 capital expenditure plans in the context of expected cash flow, potential service cost adjustments and portfolio allocation in order to prudently manage and maintain financial flexibility.

Production Estimates

The following table discloses for each product type the total volume of production estimated by McDaniel in the McDaniel Report for 2018 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	388	347	1,217	29	966
Developed Non-Producing	15	-	18	-	18
Undeveloped	-	167	212	9	212
TOTAL PROVED	403	514	1,447	38	1,196
TOTAL PROBABLE	14	203	248	9	267
TOTAL PROVED & PROBABLE	417	717	1,695	47	1,463

The estimated production volumes for the Eyehill and Leduc-Woodbend properties, which account for 25% and 52%, respectively, of McDaniel's total forecast production for the year ending December 31, 2018, is set forth below.

	Eyehill Total Oil Equivalent Boe/d	Leduc-Woodbend Total Oil Equivalent Boe/d
PROVED		
Developed Producing	341	362
Developed Non-Producing	18	-
Undeveloped	-	202
TOTAL PROVED	359	564
TOTAL PROBABLE	12	196
TOTAL PROVED & PROBABLE	371	760

Production History

The following table discloses, on a quarterly basis for the year ended December 31, 2017, certain information in respect of the Corporation's production, product prices received, royalties paid, operating expenses and resulting netback by product type.

	Quarter Ended 2017				Year Ended Dec. 31, 2017
	Mar. 31	Jun. 30	Sep. 30	Dec. 31	
Average Daily Production[(1)]					
Light and Medium Crude Oil (Bbls/d)[(2)]	679	823	746	551	700
Heavy Crude Oil (Bbls/d) [(2)]	320	360	313	630	406
Conventional Natural Gas (Mcfe/d) [(3)]	91	129	177	127	131
Combined (Boe/d)	1,015	1,205	1,088	1,202	1,128
Average Net Production Prices Received					
Light and Medium Crude Oil ($/Bbl) [(2)]	46.19	44.15	40.79	45.31	43.97
Heavy Crude Oil ($/Bbl) [(2)]	45.06	44.02	44.91	44.34	44.52
Conventional Natural Gas ($/Mcfe) [(3)]	5.30	4.16	3.14	2.05	3.50
Combined ($/Boe)	45.62	43.77	41.38	44.22	43.72
Royalties Paid					
Light and Medium Crude Oil ($/Bbl) [(2)]	3.74	4.09	3.33	3.18	3.62
Heavy Crude Oil ($/Bbl) [(2)]	4.97	5.16	4.74	3.34	4.33
Conventional Natural Gas ($/Mcfe) [(3)]	1.37	0.72	0.06	0.33	0.62
Combined ($/Boe)	4.20	4.41	3.70	3.24	3.88
Production Costs					
Light and Medium Crude Oil ($/Bbl) [(2)]	12.19	12.11	10.57	11.49	11.59
Heavy Crude Oil ($/Bbl) [(2)]	10.56	14.05	15.18	11.04	12.41
Conventional Natural Gas ($/Mcfe) [(3)]	6.52	5.62	6.48	5.01	5.92
Combined ($/Boe)	12.08	13.07	12.66	11.58	12.35
Netback Received[(4)]					
Light and Medium Crude Oil ($/Bbl) [(2)]	30.26	27.95	26.89	30.64	28.75
Heavy Crude Oil ($/Bbl) [(2)]	29.53	24.81	24.99	29.96	27.78
Conventional Natural Gas ($/Mcfe) [(3)]	(2.59)	(2.18)	(3.40)	(3.29)	(3.04)
Combined ($/Boe)	29.34	26.29	25.02	29.40	27.49

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, 2017.

	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 (%)
Eyehill	444	-	10	493	536	48
Leduc-Woodbend	-	221	7	150	253	22
Killam	73	-	1	339	131	12
Wildmere	-	72	-	-	72	6
Macklin	-	36	-	-	36	3
Eyehill South	24	-	-	-	24	2
Other minor areas	16	40	4	103	76	7
Total	557	369	22	1,085	1,128	100

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 Calgary, Alberta	President, Chief Executive Officer and Director	July 31, 2015
Tavis Carlson Calgary, Alberta	Vice-President, Finance and Chief Financial Officer and Secretary	September 1, 2015
Travis Stephenson Calgary, Alberta	Vice-President, Engineering	July 31, 2015
Robert Pinckston Calgary, Alberta	Vice-President, Exploration	July 31, 2015
Jeff Mazurak Calgary, Alberta	Vice-President, Operations	July 31, 2015
Craig Stayura Calgary, Alberta	Vice-President, Land	March 22, 2017
John McAleer(1)(2)(3) Calgary, Alberta	Director	July 31, 2015
Brian Lavergne(2)(3) Calgary, Alberta	Director	July 31, 2015
Darren Gee(1)(2) Calgary, Alberta	Director	July 31, 2015

Name and Municipality of Residence	Position Held	Date First Elected or Appointed
Robert Maitland(1)(3) Calgary, Alberta	Director	July 31, 2015

Notes:

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

As at the date hereof, the officers and directors, as a group, held, directly or indirectly, or exercise control or direction over 10,837,399 Common Shares representing 9.9% 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 31 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 16 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 18 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 29 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 14 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 11 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 27 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, 2017; (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, 2017.

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, 2017 and as at April 26, 2018, 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, 2017 the Corporation had outstanding a total of 7,210,000 Options to purchase Common Shares to its directors and officers exercisable at a weighted average price of $0.33 per Common Share with expiry dates ending December 19, 2022. As at the date hereof, the Corporation had outstanding a total of 7,210,000 Options. As at April 26, 2018, 3,006,662 Options have vested and are exercisable at an average price of $0.32 per Common Share.

Warrants

As at December 31, 2017, the Corporation had a total of 97,498,785 Performance Warrants outstanding, which Performance Warrants were issued in conjunction with the Unit offering associated with the first and second tranches of the Private Placement that closed on July 31, 2015 and August 28, 2015, respectively. As at the date hereof, the Corporation has 97,498,785 Performance Warrants outstanding. Every ten warrants entitles 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 26, 2018, 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, 2017 to December 31, 2017.

Month	High ($)	Low ($)	Volume
January 2017	0.51	0.395	3,145,428
February 2017	0.49	0.385	1,085,647
March 2017	0.475	0.40	1,387,900
April 2017	0.47	0.35	2,358,218
May 2017	0.51	0.34	7,395,818
June 2017	0.455	0.335	2,397,961
July 2017	0.38	0.33	1,341,901
August 2017	0.385	0.32	1,625,920
September 2017	0.40	0.32	714,146
October 2017	0.42	0.335	1,525,943
November 2017	0.475	0.39	2,795,594
December 2017	0.455	0.37	1,839,719

During the financial year ended December 31, 2017, no Common Shares were issued, and the Corporation granted an aggregate of 1,640,000 Options with an exercise price of $0.405 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

Government Regulation

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.

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

In order to export oil or natural gas from Canada, certain approvals are required from the NEB and the Government of Canada. The approval(s) required are dependent on the hydrocarbon substance being exported and the length of the proposed export arrangement.

Oil exports may be made pursuant to export contracts, for terms not exceeding one year in the case of light crude, and not exceeding two years in the case of heavy crude, provided that an order approving any such export has been obtained from the NEB. Any oil export to be made for a longer duration (to a maximum of 25 years) pursuant to a contract requires an exporter to obtain an export license from the NEB and the issuance of such a license requires the approval of the Governor in Council.

Natural gas and NGLs exported from Canada are subject to regulations by the NEB. Exporters are free to negotiate prices and other terms with purchasers, provided the export contracts continue to meet certain criteria prescribed by the NEB and the Governor in Council.

Altura does not export directly from Canada.

Despite some recent oil pipeline capacity expansions, the overall pipeline capacity and Canadian oil's ability to access the United States midwest and tidewater is constrained. The transportation capacity deficit is not likely to be resolved quickly given that production of heavy oil and bitumen in Canada is expected to continue to increase. As further outlined below, several pipeline projects have been proposed and are in the approvals stage, and others have recently been completed. If the proposed projects are approved and constructed, the pipelines would help to alleviate the problems that Canada faces in accessing global markets for its oil supply.

Pipeline Capacity

Despite the pipeline expansions over the past several years, there appears to be insufficient pipeline capacity to accommodate current production levels of oil and natural gas in western Canada. Pipeline capacity may limit the ability to produce and market such production, and therefore western Canadian production may receive discounted pricing. Current pipeline construction projects before various regulatory bodies, if approved, are expected to alleviate this risk. Under the Canadian constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and require approval by both the NEB and the cabinet of the federal government. However, recent years have seen a perceived lack of policy and regulatory certainty at a federal level. Although the current federal government recently introduced draft legislation to amend the current federal approval processes, it is uncertain when the new legislation will be brought into force and whether any changes to the draft legislation will be made before the legislation is brought into force. 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 on various issues such as indigenous title, the government's duty to consult and accommodate indigenous peoples and the sufficiency of environmental review processes, which creates further uncertainty. 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.

Pipeline Projects

The proposed TransCanada Energy East pipeline would carry 1.1 million bbls/d of crude oil from Saskatchewan and Alberta to refineries in eastern Canada and to a tidewater export terminal in Saint John, New Brunswick. In April 2016, the NEB released a preliminary timeline for the Energy East hearing process with an NEB report to the Governor-in-Council expected in 2018. However, in October 2017, TransCanada informed the NEB that it will no longer be proceeding with the Energy East pipeline.

In 2014, the NEB approved the Northern Gateway Pipeline with 209 conditions attached. The pipeline would have carried up to 525,000 bbls/d from Alberta to Kitimat, British Columbia for export; however, in November 2016, the Government of Canada officially rejected the Northern Gateway proposal.

Kinder Morgan Canada's proposed expansion of its existing Trans Mountain Pipeline from Edmonton, Alberta to Burnaby, BC was approved by the NEB in May 2016, and by the federal government in November 2016. The pipeline is expected to increase capacity by 590,000 bbls/d.

Enbridge's Line 3 proposed replacement project of its existing pipeline from Hardisty, Alberta to Wisconsin, USA was approved by the NEB in April 2016, and by the federal government in November 2016. The pipeline is expected to increase capacity by 370,000 bbls/d.

The TransCanada-led Keystone XL project would add 830,000 bbls/d in pipeline capacity for Canadian crude oil to flow to the American Gulf Coast market. The project may proceed following the executive order issued by President Trump inviting TransCanada to re-submit its application for a presidential permit, which it did on January 26, 2017.

The North American Free Trade Agreement

NAFTA, among the Canadian, United States and Mexican governments came into effect on January 1, 1994. Under NAFTA, the Canadian government is free to determine whether exports of energy resources to the United States or Mexico should be allowed, provided that export restrictions do not: (1) reduce the proportion of energy resources exported relative to energy resources consumed domestically, (2) impose a higher export price than domestic price, and (3) disrupt normal channels of supply.

The new administration in the United States has indicated an intention to seek renegotiation of NAFTA, the impact of which on the oil and gas industry is uncertain. Canada, the United States and Mexico began renegotiating the terms of NAFTA in mid-2017. The United States has also suggested that it might give notice of the termination of NAFTA if it is not satisfied with the outcome of the renegotiations. As of the date hereof, renegotiation discussions continue and the outcome of such negotiations remains unclear. As the United States remains Canada's largest trade partner and the largest international market for the export of crude oil, natural gas and NGLs from Canada, any changes to, or termination of, NAFTA could have an impact on western Canada's crude oil and natural gas industry, including Altura's business.

Trans-Pacific Partnership

In October 2015, the Canadian government concluded negotiations of a free trade agreement between the members of the Trans-Pacific Partnership, which includes Canada, Australia, Brunei, Chile, Japan, Malaysia, Mexico, New Zealand, Peru, Singapore, the United States and Vietnam.

The finalized proposal was signed on February 4, 2016 but could not be ratified due to U.S. withdrawal from the agreement on January 23, 2017.

Following the U.S. withdrawal from the Trans-Pacific Partnership, the remaining members including Canada, Australia, Brunei, Chile, Japan, Malaysia, Mexico, New Zealand, Peru, Singapore and Vietnam entered into the Comprehensive and Progressive Agreement for Trans-Pacific Partnership on March 8, 2018. The member countries of the Comprehensive and Progressive Trans-Pacific Partnership are currently in the process of ratifying the agreement.

Royalties and Incentives

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.

Saskatchewan

The amount payable as a royalty with respect to oil depends on the type and vintage of the oil, the quality of the oil produced in the month and the value of the oil determined monthly by the provincial government. Each month, royalty rates are adjusted based on reference prices established by the Province of Saskatchewan for each type of oil. There are separate reference prices established for each type of oil (heavy oil, Southwest designated oil, or non-heavy oil other than Southwest designated oil) which represents the average well head price received by producers during the month for sales of that oil type in Saskatchewan.

The government of Saskatchewan has introduced the Oil and Gas Orphan Fund, funded by oil and gas companies to cover the cost of cleaning up abandoned wells and facilities where the owner cannot be located or has gone out of business. The program is composed of a security deposit, based upon a formula considering assets of the well and the facility licensee against the estimated cost of decommissioning the well and facility once it is no longer producing, and an annual levy assessed to each licensee.

Canadian Environmental Regulation

The 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 and facility 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 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.

In December 2015, the UNFCCC members met in Paris, France. Canada, along with 195 other countries, signed a new climate agreement (the "**Paris Agreement**"). Under the Paris Agreement, Canada is legally bound to report and monitor its GHG emissions, though details of how this will take place have yet to be determined. Signatory countries agreed to meet every five years to review their individual progress on GHG emissions reductions and to consider amendments to their targets. The Paris Agreement came into force on November 4, 2016.

On October 3, 2016, the Government of Canada announced a pan-Canadian approach to the pricing of GHG emissions. The federal plan provides all Canadian provinces and territories one year to introduce their own carbon pricing models of either a cap and trade program or a carbon tax meeting a standard to be prescribed, failing which the federal government will begin to levy its own carbon tax on a broad set of emission sources. The initial default carbon tax is expected to begin at $10 per tonne of GHG emissions on January 1, 2018 and increase by $10 per tonne per year until it reaches $50 per tonne in 2022.

The *Pipeline Safety Act* ("**PSA**"), which came into force in June 2016, amended the *National Energy Board Act* and the Canada *Oil and Gas Operations Act* in order to strengthen the safety and security of pipelines. The PSA reinforces the "polluter pays" principle, such that operators of pipelines are liable for costs and damages of all unintended or uncontrolled releases of oil, gas or other substances. Canada was the first country to introduce absolute liability irrespective of fault, with liability in amounts up to $1 billion for major pipelines (i.e., with transport capacity over 250,000 bbls/d) or otherwise as prescribed by regulation for pipelines with lower capacity. In instances involving fault or negligence, liability is unlimited. Operators are required to maintain the financial resources necessary to meet the applicable absolute liability obligations imposed under the PSA, which is another uniquely Canadian feature of the legislation. Additionally, the PSA authorizes the NEB to impose more stringent requirements with respect to abandoned pipelines, including an obligation to maintain adequate funds to pay for abandonment costs.

Where a company is unable or unwilling to adequately respond to or clean up releases from a pipeline, the NEB has the authority to take control of that pipeline release. Claims against pipeline operators who are at fault for a pipeline release may be initiated within three years from the day on which the damage or costs were incurred and cannot be made beyond six years after the release. Such claims are to be adjudicated by a tribunal established by the PSA.

On May 12, 2017, the federal government introduced 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 second reading on October 4, 2017. 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.

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 prior to the formal impact assessment process; (ii) expanded 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 by the Minister of Environment and Climate Change or the cabinet of the federal government; (iv) analyzing a broader range of factors for projects such as alternatives to the project and social and indigenous issues; 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 lifecycle regulation of approved projects, while providing for expanded participation by communities and indigenous peoples. It is unclear if or 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 effects of the proposed regulatory scheme remain unclear.

Alberta

The Alberta Climate Leadership Plan introduced a new GHG emissions pricing regime. The *Climate Leadership Act* (the "**CLA**") received royal assent on June 13, 2016 and came into force on January 1, 2017. The *Climate Leadership Regulation* ("**CL Regulation**"), which provides further detail in respect of the carbon levy regime set out in the CLA, was released on November 3, 2016, and also came into force on January 1, 2017. The CLA establishes an Alberta carbon pricing regime in the form of a carbon levy on various types of fuel, based on rates of $20 per tonne of GHG emissions as of January 1, 2017 and $30 per tonne for 2018. The carbon levy revenue will be used to fund initiatives to reduce GHG emissions, to support Alberta's ability to adapt to climate change and for rebates or adjustments related to the carbon levy to consumers, businesses, and communities in addition to a household rebate program.

The CLA and the CL Regulation impose registration, payment, remittance, reporting and administrative obligations on applicable persons throughout the fuel supply chain. The application of the carbon levy depends on the type and quantity of fuel purchased or produced and how such fuel is used by the purchaser.

GHG emissions are regulated under the *Specified Gas Reporting Regulation* (the "**SGRR**") and the *Carbon Competitiveness Incentive Regulation* (the "**CCIR**"), both pursuant to the *Climate Change and Emissions Management Act* (Alberta). The SGRR requires facilities that emit 10,000 tonnes or more of GHGs per year to report their emissions to Alberta Environment and Parks. The CCIR, which replaced the *Specified Gas Emitters Regulation* ("**SGER**") on January 1, 2018, requires facilities that emit more than 100,000 tonnes of GHGs per year (or facilities that opt-in so they may apply for a carbon levy exemption) to meet product specific emissions intensity benchmarks. Most benchmarks are based on 80% production-weighted average emissions intensity, which means the 20% least-emissions intensive competitors face no CCIR compliance costs. For oil and gas refining, a best-in-class benchmark applies (meaning the benchmark is no more stringent than the best-performing emissions facility producing the product). Where emissions exceed the benchmark, the facility must reduce its net emissions by applying emissions offsets, emissions performance credits or fund credits against its actual emissions level. The use of fund credits is unlimited; however, the use of other credits is capped, such that a facility may address only 50 to 60% of its excess emissions through performance credits and emissions offsets. Additionally, credits will expire depending on their vintage.

Under the CLA and CL Regulations, facilities subject to the CCIR are exempt from the carbon levy. Activities integral to oil and gas production processes are exempt until 2023. At this time, the determination of what constitutes an activity that is "integral" to conventional oil and gas production is still being clarified with the Alberta government. The Corporation expects current operations to have minimal direct carbon levy exposure until 2023. It is not known what will occur in 2023 when the current exemptions are expected to end.

Saskatchewan

The Management and Reduction of Greenhouse Gases Act received Royal assent in the Province of Saskatchewan on May 20, 2010. Portions of this act came into force on January 1, 2018. This legislation will establish a provincial plan for reducing GHG emissions to meet provincial targets and promote investments in low-carbon technologies. The Province has indicated that it intends to enter into an equivalency agreement with the federal government to achieve equivalent environmental outcomes under provincial regulations. A draft of the proposed regulations to accompany the Act calls for a reduction of emissions by 20% below 2006 levels by 2020.

In December 2017, Saskatchewan introduced Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy, which is to be fully implemented by January 1, 2019. This strategy will include reporting requirements and emissions reduction targets for the upstream oil and gas industry and output-based performance standards for facilities emitting more than 25,000 tonnes of carbon dioxide equivalent per year. Large emitters will have various compliance options, including making improvements at facilities to reduce emissions intensity, purchasing a carbon offset, using best performance credits, paying into a technology fund and using market mechanisms outlined in the Paris Agreement.

Land Tenure

The respective provincial governments predominantly own the rights to crude oil and natural gas located in the western provinces. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licenses, and permits for varying terms, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Private ownership of oil and natural gas also exists in such provinces and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

The province of Alberta has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license.

Alberta also has a policy of "shallow rights reversion", which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses issued after January 1, 2009 at the conclusion of the primary term of the lease or license.

Abandonment and Reclamation Cost Risk

The current oil and gas asset A&R liability regime in Alberta as a general rule limits each party's liability to its proportionate ownership of an asset. In the case where one joint owner becomes insolvent and is unable to fund the A&R activities, the solvent counterparties can claim the insolvent party's share of the remediation costs against the OWA. The OWA administers orphaned assets and is funded through a levy imposed on licencees, based on their proportionate share of deemed A&R liabilities for oil and gas facilities, wells and unreclaimed sites in Alberta. Saskatchewan has a similar regime.

In May 2016, the Alberta Court of Queen's Bench issued a decision in the case of Redwater Energy Corporation ("**Redwater**") that trustees and receivers of insolvent parties may disclaim or renounce uneconomic oil and gas assets to the AER before commencing the sales process for the insolvent party's assets. These wells and facilities then become "orphans" to be remediated by the OWA. Prior to Redwater, the sales process for the insolvent party's assets would have typically included both the economic and uneconomic assets, and only in instances where the sales process failed to sell all of the assets, would the remaining assets be classified as orphaned assets by the AER and disclaimed to the OWA. On April 24, 2017, the Alberta Court of Appeal upheld the Redwater decision. In November 2017, the AER was granted leave to appeal the Redwater decision to the Supreme Court of Canada.

In June 2016, in response to Redwater, the AER released *Bulletin 2016-16: Licensee Eligibility*, which, among other things, implemented important changes to the AER's procedures relating to liability management ratings, licence eligibility and transfers.

In order to clarify and revise the interim rules in Bulletin 16, the AER issued *Bulletin 2016-21: Revision and Clarification on Alberta Energy Regulator's Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision* ("**Bulletin 21**") on July 8, 2016 and reaffirmed its position that an LMR of 1.0 is not sufficient to ensure that licensees will be able to address their obligations throughout the life cycle of energy development, and 2.0 remains the requirement for transferees. However, Bulletin 21 did provide the AER with additional flexibility to permit licensees to acquire additional AER-licensed assets if:

1. The licensee already has an LMR of 2.0 or higher;
2. The acquisition will improve the LMR to 2.0 or higher; or
3. The licensee is able to satisfy its obligations, notwithstanding an LMR below 2.0, by other means.

The AER provided no indication of what other means would be considered. The Alberta Court of Appeal heard the appeal of the Redwater decision on October 11, 2016, with the Court upholding the decision in *Orphan Well Association v Grant Thornton Limited*, 2017 ABCA 124. That decision has since been appealed to the Supreme Court of Canada, which has reserved its decision on the matter.

In the short term the interim measures caused delays in completing transactions and reduced the pool of possible purchasers, however, transactions have been approved following a more rigorous review by the AER, despite a transferee's liability management rating not meeting the interim requirement.

The AER 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 5 years. As of April 1, 2015, each licensee is required to bring 20% of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with *Directive 020: Well Abandonment*. The list of current wells subject to the IWCP is available on the AER's Digital Data Submission system.

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 have declined significantly since mid-2014 and 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, 2018. 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 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 GHGs and require the Corporation to comply with Alberta's greenhouse gas emissions legislation contained in the *Climate Change and Emissions Management Act* and the CCIR. The Corporation may also be required to comply with the regulatory scheme for GHG emissions ultimately adopted by the federal government, which is currently adopting sector-by-sector regulations. The direct or indirect costs of these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The future implementation or modification of GHG regulations, including increases to the compliance costs contained in SGER and Alberta's new initiative to reduce venting and fugitive methane emissions, could also have a material impact on the nature of oil and natural gas operations, including those of the Corporation.

As a result of the UNFCCC adopting the Paris Agreement on December 12, 2015, to which Canada was a participant, the Government of Canada has committed to reduce GHG emissions by 30% below 2005 levels by 2030. The mechanisms that will be implemented to meet this target have not been finalized. The Government of Canada also announced it would implement a Canada-wide price on carbon to further reduce its greenhouse gas emissions. In addition, on January 1, 2017, the *Climate Leadership Act* came into effect in the Province of Alberta, introducing a carbon tax on almost all sources of greenhouse gas emissions at a rate of $20 per tonne, increasing to $30 per tonne in January 2018. The direct or indirect costs of compliance with these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, concerns about climate change have resulted in increased opposition to the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHGs and resulting requirements, it is not possible to predict the impact on Altura and its operations and financial condition. See "*Industry Conditions – Climate Change Regulation.*"

Liability Management

Alberta and Saskatchewan have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its obligations. These programs generally involve 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 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 requirement. In addition, the liability management system 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 gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. See, "*Industry Conditions – Abandonment and Reclamation Cost Risk.*"

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, 2017 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 Corporation has no material contracts that have been 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.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Corporation during, or related to, the Corporation's most recently completed financial year other than McDaniel, the Corporation's independent reserve evaluators, and KPMG LLP, the Corporation's auditors.

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

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

AUDITORS, TRANSFER AGENT AND REGISTRAR

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

The transfer agent and registrar for the Common Shares of the Corporation is 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 12, 2018 relating to the annual general and special meeting of shareholders to be held on May 17, 2018.

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, 2017. These documents are available on the SEDAR website at www.sedar.com.

APPENDIX "A"

REPORT ON RESERVES DATA
BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

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

1. We have evaluated the Company's reserves data as at December 31, 2017. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2017 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, 2017, 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, 2017	Canada	-	76,059	-	76,059

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)

P. A. Welch, P. Eng.
President & Managing Director

Calgary, Alberta, Canada
February 21, 2018

APPENDIX "B"

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

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

An independent qualified reserves evaluator has evaluated Altura's reserves data. The report of the independent qualified reserves evaluator is presented in Appendix "A" to the Annual Information Form of Altura for the year ended December 31, 2017 (the "**AIF**").

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

(a) reviewed Altura'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 Altura'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)
David Burghardt
President & Chief Executive Officer

(signed)
Travis Stephenson
Vice-President, Engineering

(signed)
Darren Gee
Director

(signed)
John McAleer
Director

April 26, 2018