altura ENERGY INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2016

March 22, 2017

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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 or the COGE Handbook and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 or the COGE Handbook.

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

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

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

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

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

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

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

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

"**Credit Facility**" means the $4,000,000 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, draining, road building and relocating public roads, gas lines and power lines, pumping equipment and wellhead assembly;

b) Drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and 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 recovery systems;

"**Exploration Costs**" means costs incurred in identifying areas that may warrant examination and 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) Dry hole contributions and bottom hole contributions;

d) Costs of drilling and equipping exploratory wells; and

e) Costs of drilling exploratory type stratigraphic test wells;

"**Flow-Through Shares**" has the meaning ascribed thereto under the heading "*General Development of the Business – 2014*";

"**Gross**" means:

a) In relation to the Corporation's interest in production and reserves, its "Corporation gross reserves", which are the Corporation's 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;

"**Killam Acquisition**" has the meaning ascribed thereto under the heading "*General Development of the Business – 2016*";

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

"**McDaniel Report**" means the report prepared by McDaniel, in accordance with NI 51-101, dated March 7, 2017 and effective December 31, 2016;

"**Net**" means:

a) In relation to the Corporation's interest in production and reserves, the Corporation's 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, Maureen Keough, (former) Vice President, Land 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 – 2014*";

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

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

"**Performance Warrant**" has the meaning ascribed thereto under the heading "*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*";

"**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*";

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

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

"**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, 2016 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	Mcf	thousands of cubic feet
Bbls	barrels of oil or natural gas liquids	Mcfe	thousands of cubic feet equivalent
Bbls/d	barrels per day	Mcf/d	thousands of cubic feet per day
NGL	natural gas liquids	Mcfe/d	thousands of cubic feet equivalent per day

3-D	three dimensional
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 1 Bbl for 6 Mcf of natural gas
Boe/d	barrel of oil equivalent per day
GHG	greenhouse gas
m^3	cubic meters
MBOE	1,000 barrels of oil equivalent
$M	thousands of dollars
$MM	millions 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
gigajoules	MMBtu	0.950

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")

FD&A is 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 includes 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 F&D 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 as measures 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

Reserve life index or RLI is calculated by dividing the reserves (in boe) in the referenced category by the Q4 2016 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, natural gas liquids 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;
- 2017 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" or "resources" are forward-looking statements, as they involve the implied assessment, based on estimates and assumptions, that the reserves and resources 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 (1) post-Consolidation Common Share for every ten (10) 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, 2014 to December 31, 2016 the Corporation has grown its business by acquiring producing assets, land, either freehold or Crown, and drilling, completing and equipping wells on the assets owned by the Corporation, primarily in east central Alberta. Set out below is a review of the Corporation's activities during such three-year period.

2014

Overview of Capital Expenditure Program

During the year ended December 31, 2014, the Corporation executed a $7.1 million capital program and drilled six gross (4.6 net) wells in the Eyehill, Eyehill South and Provost Minor areas of Alberta. Average production for the year was 255 Boe/d.

General Business Developments

On May 29, 2014, the Corporation entered into the Credit Facility with a Canadian Chartered Bank in the initial amount of $2.0 million.

On July 16, 2014, the Corporation's Credit Facility was increased from $2.0 million to $5.0 million.

During the year ended December 31, 2014, the Corporation disposed of non-producing properties and exploration and evaluation lands in the Eyehill area for proceeds of $1.1 million and non-producing properties in the Valhalla area for proceeds of $0.1 million.

On December 18, 2014, the TSX Venture Exchange authorized the Corporation’s notice to make a normal course issuer bid ("**NCIB**") to purchase for cancellation up to 2,315,134 Common Shares of the Corporation on the open market during the period from December 24, 2014 to December 24, 2015. No Common Shares were repurchased in 2014.

On December 29, 2014, the Corporation completed a non-brokered private placement of 1,000,000 Common Shares issued on a "flow-through" basis pursuant to the Income Tax Act (Canada) ("**Flow-Through Shares**") at an issue price of $1.00 per Flow-Through Share for aggregate gross proceeds of $1.0 million.

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. Additionally, the Corporation acquired freehold and Crown leases in 16 sections of land in the Leduc-Woodbend area of Alberta and 8 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 NCIB. 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 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 for cash proceeds 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 (1) pre-Consolidation Common Share for each nine (9) 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 10 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 7 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, and 1.0 sections 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 (the "**Killam Acquisition**") 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.

Recent Developments

On January 12, 2017, the Corporation announced it drilled and completed an Upper Mannville oil well in the Leduc-Woodbend area of Alberta which represents a new Upper Mannville oil pool for the Corporation. Additionally, the Corporation confirmed its 2017 capital budget to be $17.0 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 east central Alberta. 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 a number of inherent risks. See "*Risk Factors*" in this AIF.

Principal Properties

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 800 acres are undeveloped and 480 acres are developed. Altura acquired its assets in the Eyehill area through Crown land sales. Altura drilled three wells in the area in 2016 which were brought on-stream in the third and fourth quarters of 2016. The Corporation's exploration, development and production activities in the Eyehill area are directed towards medium gravity oil in the Sparky Formation.

McDaniel assigned approximately 792.6 MBOE of proved reserves and 1,510.7 MBOE of proved plus probable reserves in the Eyehill area in the McDaniel Report.

During the year ended December 31, 2016, Altura had average production of approximately 405 Boe/d (including 356 Bbls/d of oil and liquids and 296 Mcf/d of natural gas) from 8 gross (8.0 net) producing wells in the Eyehill area. All of the 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 pipelined and processed by a third party.

Altura is evaluating waterflood opportunities to optimize its assets in the Eyehill area.

Killam Area

On September 14, 2016, the Corporation closed the Killam Acquisition which is located approximately 65 kilometers west of Wainwright, Alberta. Altura acquired a 100% working interest in 4,471 net acres of land and 25% working interest in 640 gross (160 net) acres of land in the Killam area, of which 1,600 gross (1,240 net) acres are undeveloped and 3,511 gross (3,391 net) acres are developed. 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 608.4 MBOE of proved reserves and 824.4 MBOE of proved plus probable reserves in the Killam area in the McDaniel Report.

During the year ended December 31, 2016, Altura had average production of approximately 37 Boe/d (including 20 Bbls/d of oil and liquids and 98 Mcf/d of natural gas) from 10 gross (10.0 net) producing wells in the area. Since September 14, 2016, the Killam area averaged 123 Boe/d (including 67 Bbls/d of oil and liquids and 330 Mcf/d of natural gas). All of the 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 pipelined and processed by a third party.

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 58% working interest in 2,720 gross (1,578 net) acres of land in the Eyehill South area, of which 800 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 medium gravity oil in the Sparky Formation.

McDaniel assigned approximately 57.3 MBOE of proved reserves and 110.2 MBOE of proved plus probable reserves in the Eyehill South area in the McDaniel Report.

During the year ended December 31, 2016, Altura had average production of approximately 28 Bbls/d (100% crude oil) from 4 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.

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 67% working interest in 2,560 gross (1,723 net) acres of land in the Wildmere area, of which 800 gross (672 net) acres are undeveloped and 1,760 gross (1,051 net) acres are developed. Altura drilled 2 gross (1.5 net) wells in the area in the fourth quarter of 2016 which were brought on-stream in November 2016. The Corporation's exploration, development and production activities in the Wildmere area are directed towards heavy oil in the Sparky Formation, which has been defined with vertical wells and 3-D seismic.

McDaniel assigned approximately 229.8 MBOE of proved reserves and 435.0 MBOE of proved plus probable reserves in the Wildmere area in the McDaniel Report.

During the year ended December 31, 2016, Altura had average production of approximately 19 Bbls/d (100% crude oil) from 3 gross (2.5 net) producing wells in the Wildmere area. All of the production in the area is treated on site and tied into a multi-well battery owned and operated by the Corporation. Oil sales volumes are trucked to a sales point.

Leduc-Woodbend Area

In 2015 and 2016, the Corporation acquired land through Crown land sales and land acquisitions in the Leduc-Woodbend area. Altura currently holds a 100% working interest in 36,021 net acres of land in the Leduc-Woodbend area, of which 35,376 net acres are undeveloped and 645 net acres are developed. Altura drilled one well in the area in 2016 which was brought on-stream in the fourth quarter of 2016. 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 70.1 MBOE of proved reserves and 234.8 MBOE of proved plus probable reserves in the Leduc-Woodbend area in the McDaniel Report.

During the year ended December 31, 2016, Altura had average production of approximately 21 Boe/d (including 19 Bbls/d of oil and liquids and 9 Mcf/d of natural gas) from one gross (1.0 net) producing well in the area. The production in the area was brought on-stream in November 2016 and is tied into a single well battery owned and operated by the Corporation. Oil sales volumes are trucked to a sales point and natural gas production is pipelined and processed by a third party.

Provost Minors Area

The Provost Minors area consists of a number of properties located around Provost, Alberta. Altura currently holds a 78% working interest in 33,371 gross (26,137 net) acres of land in the area, of which 17,814 gross (17,645 net) acres are undeveloped and 15,536 (8,483 net) acres are developed. Altura drilled one gross (1.0 net) well in the area in the fourth quarter of 2016 which was brought on-stream in December 2016. Oil gravity is in the range of 20° to 28° API for the upper Mannville targets in the area.

McDaniel assigned approximately 63.3 MBOE of proved reserves and 80.1 MBOE of proved plus probable reserves in the Provost Minors area in the McDaniel Report.

During the year ended December 31, 2016, Altura had average production of approximately 65 Boe/d (including 49 Bbls/d of oil and liquids and 97 Mcf/d of natural gas) from 7 gross (7.0 net) operated wells and 2 gross (0.5 net) non-operated wells in the area. All production in the area is tied into single well batteries and oil sales volumes are trucked to a sales point.

Personnel

The Corporation currently has six employees forming a full cycle multi-disciplinary team with significant experience and expertise in the Western Canadian Sedimentary Basin. The Corporation believes that this team can grow the Corporation to a significantly greater size under efficient reserve acquisition and development metrics.

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 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 and the report of management and directors on reserves data and other information in Form 51-101F3 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 with an effective date of December 31, 2016 and a preparation date of March 7, 2017. The Reserves Data summarizes the oil, natural gas liquids and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using forecast prices and costs.

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

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

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

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

Altura determined the future net revenue and present value of future net revenue after income tax expenses by utilizing McDaniel's before income tax future net revenue and the Corporation's estimate of income tax. Altura's estimates of the after-income tax value of future net revenue have been prepared based on before income tax reserves information and include assumptions and estimates of the Corporation's tax pools and the sequences of claims and rates of claim thereon. The values shown may not be representative of future income tax obligations, applicable tax horizon or after tax valuation. The after tax net present value of Altura's oil and natural gas properties reflects the tax burden of its properties on a stand-alone basis. It does not provide an estimate of the value of the Corporation as a business entity, which may be significantly different. Altura's consolidated financial statements and management's discussion and analysis for the year ended December 31, 2016 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 AND GAS RESERVES
FORECAST PRICES AND COSTS AS OF DECEMBER 31, 2016

Reserves Category	Light and Medium Crude Oil		Heavy Crude Oil		Conventional Natural Gas		Natural Gas Liquids		Total Oil Equivalent	
	Gross(1) (Mbbl)	Net(2) (Mbbl)	Gross(1) (Mbbl)	Net(2) (Mbbl)	Gross(1) (MMcf)	Net(2) (MMcf)	Gross(1) (Mbbl)	Net(2) (Mbbl)	Gross(1) (Mboe)	Net(2) (Mboe)
PROVED										
Developed Producing	700.1	620.1	172.5	152.3	1,275.9	1,151.1	13.9	10.2	1,099.2	974.5
Developed Non-Producing	-	-	-	-	-	-	-	-	-	-
Undeveloped	467.9	393.9	116.3	109.1	803.6	707.2	4.1	3.6	722.2	624.4
TOTAL PROVED	1,168.0	1,014.0	288.9	261.4	2,079.5	1,858.3	18.0	13.8	1,821.4	1,598.9
TOTAL PROBABLE	823.4	695.5	343.3	314.7	1,144.1	1,028.6	16.3	13.7	1,373.8	1,195.4
TOTAL PROVED & PROBABLE	1,991.4	1,709.5	632.2	576.1	3,223.6	2,886.9	34.3	27.5	3,195.2	2,794.2

Notes:

(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, 2016

Reserves Category	Before Income Taxes Discounted at (%/year)					After Income Taxes Discounted at (%/year)					Unit Value Before Tax
	0% (MM$)	5% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)	0% (MM$)	5% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)	@10%(1) ($/BOE)
PROVED											
Developed Producing	29.9	26.2	23.3	21.0	19.2	29.1	25.7	22.9	20.7	19.0	23.94
Developed Non-Producing	-	-	-	-	-	-	-	-	-	-	-
Undeveloped	14.5	10.7	8.0	6.1	4.6	10.6	7.7	5.6	4.1	3.0	12.85
TOTAL PROVED	44.4	37.0	31.3	27.1	23.8	39.7	33.4	28.5	24.8	22.0	19.61
TOTAL PROBABLE	43.7	31.0	23.2	18.1	14.6	32.0	22.6	16.7	12.9	10.3	19.40
TOTAL PROVED & PROBABLE	88.0	68.0	54.5	45.2	38.4	71.7	55.9	45.2	37.7	32.2	19.52

Note:

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

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
FORECAST PRICES AND COSTS AS OF DECEMBER 31, 2016

Reserves Category	Revenue [(1)] M$	Royalties [(2)] M$	Operating Costs M$	Development Costs M$	Abandonment & Reclamation M$	Future Net Revenue Before Income Taxes M$	Income Taxes M$	Future Net Revenue After Income Taxes M$
TOTAL PROVED	105,941	12,843	35,681	9,697	3,335	44,386	4,701	39,685
TOTAL PROVED & PROBABLE	197,705	24,665	63,948	16,822	4,232	88,038	16,378	71,660

Notes:

(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, 2016

Reserves Category	PRODUCT TYPE	Future Net Revenue Before Income Taxes (discounted at 10%) M$	UNIT VALUE[(1)] $/Mcf $/bbl
TOTAL PROVED	Light and Medium Crude Oil (Including Solution Gas and By-products)	26,197	25.84
	Heavy Crude Oil (Including Solution Gas and By-products)	5,188	19.85
	Conventional Natural Gas (Including By-products)	(32)	(-2.27)
	TOTAL	**31,353**	
TOTAL PROVED & PROBABLE	Light and Medium Crude Oil (Including Solution Gas and By-products)	44,686	26.14
	Heavy Crude Oil (Including Solution Gas and By-products)	9,882	17.15
	Conventional Natural Gas (Including By-products)	(28)	(1.56)
	TOTAL	**54,540**	

Note:

(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

McDaniel employed the following pricing, exchange rate and inflation rate assumptions as of December 31, 2016 in the McDaniel Report in estimating reserves data using forecast prices and costs. Benchmark weighted average historical prices for 2016 are also reflected in the table below.

	Crude Oil				Natural Gas	Natural Gas Liquids			
Year	**WTI Crude Oil[(1)] $US/bbl**	**Edmonton Light Crude Oil[(2)] $Cdn/bbl**	**Western Canadian Select Crude Oil[(3)] $C/bbl**	**Alberta Heavy Crude Oil[(4)] $C/bbl**	**Alberta AECO Spot Price $C/MMBtu**	**Edmonton Cond. & Natural Gasolines $C/bbl**	**Edmonton Butanes $Cdn/bbl**	**Inflation %**	**US/CAN Exchange Rate $US/$CAN**
2016	43.30	53.80	39.05	33.35	2.10	56.15	33.80		0.760
Forecast[(4)]									
2017	55.00	69.80	53.70	46.50	3.40	72.80	43.50	0.0	0.750
2018	58.70	72.70	58.20	50.50	3.15	75.80	47.90	2.0	0.775
2019	62.40	75.50	61.90	54.00	3.30	78.60	49.80	2.0	0.800
2020	69.00	81.10	66.50	58.00	3.60	84.30	56.40	2.0	0.825
2021	75.80	86.60	71.00	61.90	3.90	89.80	63.40	2.0	0.850
2022	77.30	88.30	72.40	63.10	3.95	91.60	64.70	2.0	0.850
2023	78.80	90.00	73.80	64.40	4.10	93.40	65.90	2.0	0.850
2024	80.40	91.80	75.30	65.60	4.25	95.20	67.30	2.0	0.850
2025	82.00	93.70	76.80	67.00	4.30	97.20	68.60	2.0	0.850
2026	83.70	95.60	78.40	68.40	4.40	99.20	70.00	2.0	0.850
2027	85.30	97.40	79.90	69.60	4.50	101.10	71.40	2.0	0.850
2028	87.00	99.40	81.50	71.10	4.60	103.10	72.80	2.0	0.850
2029	88.80	101.40	83.10	72.50	4.65	105.20	74.30	2.0	0.850
2030	90.60	103.50	84.90	74.00	4.75	107.40	75.80	2.0	0.850
2031	92.40	105.50	86.50	75.40	4.85	109.50	77.30	2.0	0.850
Thereafter	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.0	0.850

Notes:

(1) West Texas Intermediate at Cushing Oklahoma 40 degrees API/0.5% sulphur
(2) Edmonton Light Sweet 40 degrees API, 0.3% sulphur
(3) Western Canadian Select at Hardisty, Alberta
(4) Heavy crude oil 12 degrees API at Hardisty Alberta (after deduction of blending costs to reach pipeline quality)

Reconciliation of Changes in Reserves

The following table sets forth a reconciliation of the Corporation's gross reserves as at December 31, 2016, derived from the McDaniel Report using forecast prices and cost estimates, reconciled to the Corporation's gross reserves as at December 31, 2015.

RECONCILIATION OF GROSS RESERVES BY PRODUCT TYPE
FORECAST PRICES AND COSTS

	Light and Medium Crude Oil			Heavy Crude Oil			Conventional Natural Gas		
FACTORS	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved & Probable (Mbbl)**	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved & Probable (Mbbl)**	**Proved (Mmcf)**	**Probable (Mmcf)**	**Proved & Probable (Mmcf)**
December 31, 2015	544.9	446.5	991.4	102.1	132.6	234.7	423.8	317.7	741.5
Extensions & Improved Recovery	160.1	344.6	504.6	116.3	262.5	378.8	126.2	385.5	511.8
Technical Revisions[(1)]	228.8	(106.5)	122.3	25.7	(87.5)	(61.8)	261.0	(53.6)	207.4
Discoveries	-	-	-	66.4	35.8	102.3	56.9	35.9	92.8
Acquisitions	388.9	138.8	527.7	-	-	-	1,394.9	458.7	1,853.6
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors[(2)]	-	-	-	-	-	-	-	-	-
Production	(154.6)	-	(154.6)	(21.7)	-	(21.7)	(183.4)	-	(183.4)
December 31, 2016	1,168.0	823.4	1,991.4	288.9	343.4	623.2	2,079.5	1,144.1	3,223.6

	Natural Gas Liquids			Total Oil Equivalent		
FACTORS	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved & Probable (Mbbl)**	**Proved (Mboe)**	**Probable (Mboe)**	**Proved & Probable (Mboe)**
December 31, 2015	7.2	5.4	12.7	724.9	637.5	1,362.4
Extensions & Improved Recovery	2.2	8.8	11.0	299.6	680.1	979.7
Technical Revisions[(1)]	7.3	(0.1)	7.2	305.2	(203.0)	102.3
Discoveries	2.3	1.4	3.7	78.2	43.3	121.5
Acquisitions	2.1	0.7	2.8	623.4	216.0	839.4
Dispositions	-	-	-	-	-	-
Economic Factors[(2)]	-	-	-	-	-	-
Production	(3.1)	-	(3.1)	(210.0)	-	(210.0)
December 31, 2016	18.0	16.3	34.3	1,821.4	1,373.8	3,195.2

Notes:

(1) Includes technical revisions due to reservoir performance, geological and engineering changes as well as changes of category from probable to proven.

(2) Includes economic revisions due to changes in economic limits and related to price and royalty factor changes.

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

Undeveloped reserves are attributed by McDaniel in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Proved and probable undeveloped reserves have been assigned in accordance with engineering and geological practices as defined under NI 51-101. In general, the Corporation plans to develop all of the proved and probable undeveloped reserves over the next three years.

In some cases, it will take longer than three years to develop these reserves. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to commodity pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion formation is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) 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.

	Light and Medium Crude Oil (Mbbl)	Heavy Crude Oil (Mbbl)	Conventional Natural Gas (MMcf)	Natural Gas Liquids (Mbbl)
Year	**First Attributed**	**First Attributed**	**First Attributed**	**First Attributed**
2014	654.3	7.1	204.3	2.0
2015	-	-	-	-
2016	58.2	116.3	51.8	0.9

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 722.2 MBOE of proved undeveloped reserves in the McDaniel Report with $9.7 million of associated undiscounted capital, all of which is forecast to be spent in the first three 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.

	Light and Medium Crude Oil (Mbbl)	Heavy Crude Oil (Mbbl)	Conventional Natural Gas (MMcf)	Natural Gas Liquids (Mbbl)
Year	**First Attributed**	**First Attributed**	**First Attributed**	**First Attributed**
2014	495.4	109.6	70.4	0.7
2015	-	-	-	-
2016	316.1	262.5	362.2	8.4

Probable undeveloped reserves have been assigned in areas where the reserves can be estimated with less certainty. It is equally likely that 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 1,010.2 MBOE of probable undeveloped reserves in the McDaniel Report with $7.1 million of associated undiscounted capital, all of which is forecast to be spent in the first three 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 $6.28 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 $1.16 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, 2016 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**
2017	6,102	7,252
2018	3,030	8,439
2019	566	1,132
2020	-	-
2021	-	-
Thereafter	-	-
Total for all years undiscounted	9,697	16,822
Total for all years discounted at 10% per year	8,916	15,240

Altura expects to use a combination of internally generated cash from operations, working capital 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, recycle ratio, reserve replacement and reserve life index for 2016.

	2016
Total capital expenditures, acquisitions and dispositions ($000)	17,492
Change in future development costs – Total Proved ($000)	5,704
Change in future development costs – Total Proved & Probable ($000)	7,664
Q4 2016 production (boe/d)	988
Q4 2016 Operating netback ($/boe)(1)	30.02
2016 Operating netback ($/boe)(1)	25.29
Proved Developed Producing	
FD&A costs ($/boe)(1)	19.99
Recycle ratio(1) (Q4 2016 operating netback)	1.5
Recycle ratio(1) (2016 operating netback)	1.3
Reserve replacement(1)	417%
RLI (years)(1)	3.0
Total Proved	
FD&A costs ($/boe)(1)	17.76
Recycle ratio(1) (Q4 2016 operating netback)	1.7
Recycle ratio(1) (2016 operating netback)	1.4
Reserve replacement(1)	622%
RLI (years)(1)	5.0
Total Proved & Probable	
FD&A costs ($/boe)(1)	12.32
Recycle ratio(1) (Q4 2016 operating netback)	2.4
Recycle ratio(1) (2016 operating netback)	2.1
Reserve replacement(1)	973%
RLI (years)(1)	8.8

Notes:

(1) "Operating netback", "FD&A costs", "Recycle ratio", "Reserve replacement", "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, 2016.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	29	25.2	17	15.6	3	3.0	34	24.2
Saskatchewan	0	0	1	1.0	0	0	0	0
Total	29	25.2	18	16.6	3	3.0	34	24.2

Notes:

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

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

Of the non-producing wells, no wells were drilled in 2016 that were capable of production and had reserves assigned to them.

Properties with no Attributed Reserves

The following table summarizes, effective December 31, 2016, 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 2018. See "*Risk Factors – Income Taxes*".

Costs Incurred

The following table summarizes capital expenditures incurred by the Corporation during the year ended December 31, 2016.

	Property Acquisitions			
($000s)	**Proved Properties**	**Unproved Properties**	**Exploration Costs**	**Development Costs**
Total	4,093	-	5,318	8,206

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, 2016. All wells were drilled in Canada.

	Exploratory Wells		**Development Wells**	
	Gross	**Net**	**Gross**	**Net**
Crude Oil	1	1.0	6	5.5
Natural Gas	-	-	-	-
Service	-	-	-	-
Stratigraphic Test	-	-	-	-
Dry	-	-	-	-
Total	1	1.0	6	5.5

Planned Capital Expenditures

In November 2016, Altura announced its planned capital expenditure budget of $17.0 million for 2017. The budget includes 11 gross (10.2 net) horizontal wells targeting the Upper Mannville Group for total drilling, completion, equipping and tie-in capital of $12.4 million. In addition, up to $2.0 million will be allocated to acquiring undeveloped land and seismic, $2.1 million will be allocated to infrastructure investments related to the initiation of a waterflood in the Eyehill area and $0.5 million will be allocated to abandonment, reclamation and other corporate costs.

With the current volatility of commodity prices, Altura continues to actively monitor the 2017 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 2017 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	498	137	716	11	765
Developed Non-Producing	-	-	-	-	-
Undeveloped	131	19	178	1	181
TOTAL PROVED	629	156	894	12	947
TOTAL PROBABLE	119	21	120	2	162
TOTAL PROVED & PROBABLE	748	177	1,014	14	1,108

The estimated production volumes for the Eyehill property, which accounts for 58 percent of McDaniel's total forecast production for the year ending December 31, 2017, is set forth below.

	Eyehill Total Oil Equivalent BOE/d
PROVED	
Developed Producing	422
Developed Non-Producing	-
Undeveloped	103
TOTAL PROVED	525
TOTAL PROBABLE	126
TOTAL PROVED & PROBABLE	651

Production History

The following table discloses, on a quarterly basis for the year ended December 31, 2016, certain information in respect of the Corporation's production, product prices received, royalties paid, operating expenses and resulting netback by product type.

	Quarter Ended 2016				Year Ended
	Mar. 31	Jun. 30	Sep. 30	Dec. 31	Dec. 31, 2016
Average Daily Production[(1)]					
Light and Medium Crude Oil (Bbl/d)[(2)]	371	288	538	768	492
Heavy Crude Oil (Bbl/d) [(2)]	11	12	18	202	61
Conventional Natural Gas (Mcfe/d) [(3)]	138	139	108	101	121
Combined (BOE/d)	405	323	574	988	574
Average Net Production Prices Received					
Light and Medium Crude Oil ($/Bbl) [(2)]	26.38	40.96	42.29	45.96	40.55
Heavy Crude Oil ($/Bbl) [(2)]	20.57	35.43	37.68	43.86	41.92
Conventional Natural Gas ($/Mcfe) [(3)]	2.72	2.92	3.15	4.41	3.23
Combined ($/BOE)	25.65	39.08	41.41	45.20	39.95
Royalties Paid					
Light and Medium Crude Oil ($/Bbl) [(2)]	1.26	2.09	3.22	3.36	2.74
Heavy Crude Oil ($/Bbl) [(2)]	-	-	-	4.82	4.01
Conventional Natural Gas ($/Mcfe) [(3)]	0.09	0.07	0.10	0.69	0.55
Combined ($/BOE)	1.33	2.06	3.13	3.67	2.90
Production Costs					
Light and Medium Crude Oil ($/Bbl) [(2)]	11.64	13.10	8.79	10.72	10.71
Heavy Crude Oil ($/Bbl) [(2)]	33.80	28.25	25.18	12.14	14.89
Conventional Natural Gas ($/Mcfe) [(3)]	2.58	3.78	6.48	6.68	4.65
Combined ($/BOE)	12.48	14.33	10.26	11.51	11.76
Netback Received ($/BOE)[(4)]					
Light and Medium Crude Oil ($/Bbl) [(2)]	13.48	25.77	30.28	31.88	27.10
Heavy Crude Oil ($/Bbl) [(2)]	(13.23)	7.18	12.50	26.90	23.02
Conventional Natural Gas ($/Mcfe) [(3)]	0.05	(0.93)	(3.43)	(2.96)	(1.97)
Combined ($/BOE)	11.84	22.69	28.02	30.02	25.29

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, 2016.

	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 (%)
Alberta						
Eyehill	351	-	5	296	405	71
Eyehill South	28	-	-	-	28	5
Provost Minor	21	21	1	51	52	9
Killam	20	-	0	98	36	6
Bowden	3	-	2	47	13	2
Wildmere	-	19	-	-	19	3
Leduc-Woodbend	-	19	-	9	21	4
Total	423	59	8	501	574	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)(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 10,785,899 Common Shares representing 9.90% 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 30 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 a member of 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 15 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 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 member of the Institute of Chartered Accountants of Alberta since 2005.

Travis Stephenson, Vice-President, Engineering

Mr. Stephenson is a Professional Engineer with 17 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 a member of APEGA.

Robert Pinckston, Vice-President, Exploration

Mr. Pinckston has 28 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 a Professional Geologist registered with APEGA.

Jeff Mazurak, Vice-President, Operations

Mr. Mazurak is a Professional Engineer with 13 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 a member of APEGA.

Craig Stayura, Vice-President, Land

Mr Stayura is a Landman with over 10 years of industry experience. Most recently, as a negotiating landman for Mosaic Energy Ltd., 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 26 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 Resources Ltd., 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.

Robert 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* 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.

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, 2016; (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, 2016.

Interest of Management and Others in Material Transactions

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

AUDIT COMMITTEE INFORMATION

Audit Committee Charter

The Board has adopted a written charter and terms of reference for the Audit Committee, which sets out the Audit Committee's responsibility for, among other things, reviewing the Corporation's financial statements and the Corporation's public disclosure documents containing financial information and reporting on such review to the Board, ensuring the Corporation's compliance with legal and regulatory requirements, overseeing qualifications, engagement, compensation, performance and independence of the Corporation's external auditors, and reviewing, evaluating and approving the internal control and risk management systems that are implemented and maintained by management. A copy of the Audit Committee Charter is attached to this AIF as Appendix "C".

Composition of the Audit Committee and Relevant Education and Experience

The Audit Committee consists of Messrs. Robert Maitland (Chair), Darren Gee and John McAleer. Each of the members of the Audit Committee is considered "financially literate" and "independent" within the meaning of National Instrument 52–110 – *Audit Committees*.

The Corporation believes that each of the members of the Audit Committee possesses: (a) an understanding of the accounting principles used by the Corporation to prepare its financial statements; (b) the ability to assess the general application of such accounting principles in connection with the accounting for estimates, accruals and provisions; (c) experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the Corporation's financial statements, or experience actively supervising one or more individuals engaged in such activities; and (d) an understanding of internal controls and procedures for financial reporting.

For a summary of the education and experience of each member of the Audit Committee that is relevant to the performance of his responsibilities as a member of the Audit Committee, see "*Management of the Corporation – Directors and Officers – Biographies*".

Pre-Approval Policies and Procedures for the Engagement of Non–Audit Services

The Audit Committee must pre-approve all non-audit services to be provided to the Corporation by its external auditors. The Audit Committee may delegate to one or more members the authority to pre-approve non-audit services, provided that the member reports to the Audit Committee at the next scheduled meeting such pre-approval and the member complies with such other procedures as may be established by the Audit Committee from time to time.

External Audit Service Fees

The following table summarizes the fees paid by the Corporation to its auditors, KPMG LLP, for external audit and other services in each of the last two financial years.

Year	Audit Fees (1)	Audit -Related Fees	Tax Fees	All Other Fees
	($)	**($)**	**($)**	**($)**
2016	68,000	-	9,577	-
2015	42,000	-	-	-

Note:

(1) Represents the aggregate fees for services related to the audit of annual financial statements and review of quarterly financial statements

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, 2016 and as at March 22, 2017, 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, 2016 the Corporation had outstanding a total of 5,570,000 Options to purchase Common Shares to its directors and officers exercisable at a weighted average price of $0.31 per Common Share with expiry dates ending November 30, 2021. As at the date hereof, the Corporation had outstanding a total of 5,570,000 Options. At March 22, 2017, 1,150,003 Options have vested and are exercisable at $0.34.

Warrants

As at December 31, 2016, the Corporation had 97,498,785 Performance Warrants outstanding, issued in conjunction with the Unit offering associated with the Private Placement that closed on July 31, 2015 and August 28, 2015. As at the date hereof, the Corporation has 97,498,785 Performance Warrants outstanding. Every ten (10) warrants entitles the holder thereof to purchase one (1) 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. At March 22, 2017, no Performance Warrants have yet 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, 2016 to December 31, 2016.

Month	High ($)	Low ($)	Volume
January 2016	0.38	0.20	856,961
February 2016	0.30	0.235	371,292
March 2016	0.28	0.25	453,912
April 2016	0.28	0.20	1,653,751
May 2016	0.31	0.235	1,647,321
June 2016	0.29	0.215	808,150
July 2016	0.28	0.255	440,189
August 2016	0.35	0.245	1,138,748
September 2016	0.29	0.23	1,349,968
October 2016	0.345	0.26	1,773,690
November 2016	0.30	0.245	4,684,354
December 2016	0.45	0.26	6,538,360

During the financial year ended December 31, 2016, the Corporation granted an aggregate of 2,120,000 Options with an exercise price of $0.27 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 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 natural gas liquids ("**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 National Energy Board (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 with 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 pursuant to a contract of longer duration (to a maximum of 25 years) 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.

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 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 March 2018. Energy East panel sessions began in New Brunswick in August 2016, but were later suspended following protests at a panel session in Montreal. In January, 2017, the NEB announced the appointment of three new panel members who will be responsible for continuing the review of the project.

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

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 U.S. government under the Trump Administration has indicated an intent to renegotiate the terms of NAFTA.

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 Canadian government is currently in the process of consulting with Canadians on the agreement and states that it will provide greater transparency and more predictable market access for cross-border trade in services related to the oil and gas industry.

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

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 their 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 Alberta Energy Regulator ("**AER**") on an annual basis.

Producers pay a flat royalty rate of 5 percent 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 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 percent 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 percent 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 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 regulation pursuant to provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced or utilized in association with certain oil and natural gas industry operations and can affect the location of wells and facilities and the extent to which exploration and development is permitted. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such legislation may result in the imposition of fines and penalties, the suspension or revocation of necessary licenses and authorizations, restrictions on the transfer of well and facility sites and civil liability for pollution damage.

Alberta

The Alberta Climate Leadership Plan introduced a new greenhouse gas ("**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. Under the CLA and CL Regulations, facilities subject to the Specified Gas Emitters Regulation (Alberta) (the "**SGER**") 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. However, this Act is still awaiting proclamation. The new 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.

Federal (Canada)

In December, 2015 the United Nations Framework Convention on Climate Change (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 counties agreed to meet every five years to review their individual progress on GHG emissions reductions and 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 a 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.

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.

Liability Management Rating Programs

Alberta

In Alberta, the AER implements the Licensee Liability Rating Program (the "**AB LLR Program**"). The AB LLR Program is a liability management program governing most conventional upstream oil and natural gas wells, facilities and pipelines. The Alberta Oil and Gas Orphan Abandonment and Reclamation Association establishes an orphan fund (the "**Orphan Fund**") to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program if a licensee or working interest participant becomes defunct. The Orphan Fund is funded by licensees in the AB LLR Program through a levy administered by the AER. The AB LLR Program is designed to minimize the risk to the Orphan Fund posed by unfunded liability of licensees and prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The AB LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the AER with a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month and failure to post the required security deposit may result in the initiation of enforcement action by the AER.

Made effective in three phases, from May 1, 2013 to August 1, 2015, the AER implemented important changes to the AB LLR Program (the "**Changes**") that resulted in a significant increase in the number of oil and natural gas companies in Alberta that are required to post security. The Changes affect the deemed parameters and costs used in the formula that calculates the ratio of deemed liabilities to deemed assets under the AB LLR Program, increasing a licensee's deemed liabilities and rendering the industry average netback factor more sensitive to asset value fluctuations. The Changes stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

On June 20, 2016, the Alberta Energy Regulator issued Bulletin *2016-16, Licensee Eligibility—Alberta Energy Regulator Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision* ("**Bulletin 16**") in an urgent response to a decision from the Alberta Court of Queen's Bench, which is currently under appeal with the Court of Appeal of Alberta. In Redwater Energy Corporation (Re), 2016 ABQB 278 ("**Redwater**"), Chief Justice Wittman found that there was an operational conflict between the abandonment and reclamation provisions of Alberta's *Oil and Gas Conservation Act* and the *Bankruptcy and Insolvency Act*, and that receivers and trustees have the right to renounce assets within insolvency proceedings. Such a conflict renders the Alberta Energy Regulator's legislated authority unenforceable to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is insolvent. Effectively, this means that abandonment costs will be borne by the industry-funded Orphan Fund or the province in these instances because any resources of the insolvent licensee will first be used to satisfy secured creditors under the *Bankruptcy and Insolvency Act*. Bulletin 16 provides interim rules to govern while the case is appealed and while the Government of Alberta can develop appropriate regulatory measures to adequately address environmental liabilities. Three changes were implemented to minimize the risk to Albertans:

1. The Alberta Energy Regulator will consider and process all applications for licence eligibility under *Directive 067: Applying for Approval to Hold EUB Licences* as non-routine and may exercise its

discretion to refuse an application or impose terms and conditions on a licencee eligibility approval if appropriate in the circumstances.

2. For holders of existing but previously unused licence eligibility approvals, prior to approval of any application (including licence transfer applications), the Alberta Energy Regulator may require evidence that there have been no material changes since approving the licence eligibility. This may include evidence that the holder continues to maintain adequate insurance and that the directors, officers, and/or shareholders are substantially the same as when licence eligibility was originally granted.

3. As a condition of transferring existing Alberta Energy Regulator licences, approvals, and permits, the Alberta Energy Regulator will require all transferees to demonstrate that they have a liability management rating, being the ratio of a licensee's assets to liabilities, of 2.0 or higher immediately following the transfer.

In order to clarify and revise the interim rules in *Bulletin 16*, the Alberta Energy Regulator 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 a liability management rating 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 Alberta Energy Regulator with additional flexibility to permit licensees to acquire additional Alberta Energy Regulator-licensed assets if:

1. The licensee already has a liability management rating of 2.0 or higher;

2. The acquisition will improve the licensee's liability management rating to 2.0 or higher; or

3. The licensee is able to satisfy its obligations, notwithstanding an liability management rating below 2.0, by other means.

The Alberta Energy Regulator provided no indication of what other means would be considered. 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 Alberta Energy Regulator, despite a transferee's liability management rating not meeting the interim requirement. The Alberta Court of Appeal heard the appeal of the Redwater decision on October 11, 2016, with the Court reserving its decision.

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.

Saskatchewan

In Saskatchewan, the Ministry of the Economy administrates the Licensee Liability Rating Program. The Licensee Liability Rating Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to an orphan fund (the "**Oil and Gas Orphan Fund**") established under *The Oil and Gas Conservation Act*. The Oil and Gas Orphan Fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the Licensee Liability Rating Program when a licensee or working interest participant is defunct or missing. The Licensee Liability Rating Program requires a licensee whose deemed liabilities exceed its deemed assets to post a security deposit. The ratio of deemed assets to liabilities is assessed once each month for all licensees of oil, gas and service wells and upstream oil and gas facilities. On August 19, 2016, the Ministry of the Economy released a notice to all operators that it would follow the Alberta Energy Regulator's interim rules by processing all licence transfer applications as non-routine until further notice.

Accountability and Transparency

On June 1, 2015, the federal Extractive Sector Transparency Measures Act, ("**ESTMA**") came into effect. This new 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 CDN $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. The reporting requirement for payments made to First Nations governments has been deferred until May 31, 2017. Any persons or entities found in violation of the Act (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, our existing reserves, and the production from them, will decline over time as it produces from such reserves. A future increase in reserves will depend on both its ability to explore and develop existing properties and on its 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 our 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, 2017. 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 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 also has investments in marketable securities, the potential disposition of which may provide additional funds to support capital programs. 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 our projects. An increase in royalties would reduce our earnings and could make future capital investments, or our 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 intends to undertake certain waterflooding programs which involve the injection of water or other liquids into an oil reservoir to increase production from the reservoir and to decrease production declines. To undertake such waterflooding activities the Corporation needs to have access to sufficient volumes of water, or other liquids, to pump into the reservoir to increase the pressure in the reservoir. There is no certainty that the Corporation will have access to the required volumes of water. In addition, in certain areas there may be restrictions on water use for activities such as waterflooding. If the Corporation is unable to access such water it may not be able to undertake waterflooding activities, which may reduce the amount of 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 our 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 and Operational Matters*".

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.

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 or issuance of clean up orders in respect of Altura or its properties. Such legislation may be changed to impose higher standards and potentially more costly obligations on Altura, and there can be no assurance that Altura will be able to satisfy its actual future environmental and reclamation obligations.

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

Abandonment and Reclamation Costs

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

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

Climate Change Regulations

The Canadian federal government has announced its plan to levy a carbon tax of $10 per tonne of GHG emissions starting January 1, 2018 in each province and territory that does not at that time have a carbon tax or cap and trade system, with the $10 per tonne federal levy increasing $10 per tonne per year until it reaches $50 per tonne on January 1, 2022. Further, both the Alberta and federal governments have announced that they will each be introducing regulations to reduce methane emissions from the oil and gas sector by up to 45% by 2025. It is likely that any methane reduction regulations which are eventually adopted by the federal and provincial governments will materially impact the nature of oil and gas operations, including those carried out by Altura.

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 our deemed assets to deemed liabilities or other changes to the requirements of liability management programs may result in significant increases to the our compliance requirement. In addition, the liability management system may prevent or interfere with our 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 – Liability Management Rating Programs*".

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, 2016 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 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 or 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. Investors who are not willing to rely on the management of Altura should not invest in the common shares.

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 such entities fail to meet their contractual obligations, such failures could have a material adverse effect on the Corporation, its cash flow from operations and its liquidity structure.

Income Taxes

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

Forward-Looking Statements may Prove Inaccurate

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

MATERIAL CONTRACTS

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

1. the Reorganization and Investment Agreement (see "*General Development of the Business – Recent Developments*").

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

INTERESTS OF EXPERTS

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

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

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 18, 2016 relating to the annual general and special meeting of shareholders held on May 18, 2016.

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, 2016. 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, 2016. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2016 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, 2016, 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, 2016	Canada	-	54,540.0	-	54,540.0

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
March 7, 2017

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, 2016 (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)
Brian Lavergne
Director

March 22, 2017

APPENDIX "C"

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

CHARTER

1. Purpose

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

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

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

(c) all audit processes.

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

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

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

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

2. Composition and Process

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

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

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

(d) The Chair shall, in consultation with management and the external auditor and internal

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

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

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

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

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

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

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

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

3. Authority

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

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

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

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

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

4. Relationship with External Auditors

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

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

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

5. Accounting Systems, Internal Controls and Procedures

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

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

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

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

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

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

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

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

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

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

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

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

6. Statutory and Regulatory Responsibilities

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

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

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

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

7. Reporting

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

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

8. Other Responsibilities

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

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