# ANNUAL INFORMATION FORM

## FOR THE YEAR ENDED DECEMBER 31, 2015

**April 29, 2016**

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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);

"**Action Plan**" has the meaning ascribed thereto under the heading "*Industry Conditions*";

"**AB LLR Program**" has the meaning ascribed thereto under the heading "*Industry Conditions*";

"**AER**" has the meaning ascribed thereto under the heading "*Industry Conditions*";

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

"**ALSA**" has the meaning ascribed thereto under the heading "*Industry Conditions*";

"**ALUF**" has the meaning ascribed thereto under the heading "*Industry Conditions*";

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

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

"**Changes**" has the meaning ascribed thereto under the heading "*Industry Conditions*";

"**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 $6,500,000 revolving bank facility of the Corporation, as amended from time to time;

"**Development Costs**" means costs incurred to obtain access to 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;

"**Directive 13**" has the meaning ascribed thereto under the heading "*Industry Conditions*";

"**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 – 2013*";

"**Fund**" has the meaning ascribed thereto under the heading "*Industry Conditions*";

"**GHG**" has the meaning ascribed thereto under the heading "*Industry Conditions*";

"**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;

"**IWCP**" has the meaning ascribed thereto under the heading "*Industry Conditions*";

"**LARP**" has the meaning ascribed thereto under the heading "*Industry Conditions*";

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

"**McDaniel Report**" means the report prepared by McDaniel, in accordance with NI 51-101, dated March 9, 2016 and effective December 31, 2015;

"**MRF**" has the meaning ascribed thereto under the heading "*Industry Conditions*";

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

"**NEB**" has the meaning ascribed thereto under the heading "*Industry Conditions*";

"**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;

"**Orphan Fund**" has the meaning ascribed thereto under the heading "*Industry Conditions*";

"**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*";

"**Prosperity Act**" has the meaning ascribed thereto under the heading "*Industry Conditions*";

"**Regulated Emitters**" has the meaning ascribed thereto under the heading "*Industry Conditions*";

"**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 the 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*";

"**SGER**" has the meaning ascribed thereto under the heading "*Industry Conditions*";

"**SSRP**" has the meaning ascribed thereto under the heading "*Industry Conditions*";

"**TPP**" has the meaning ascribed thereto under the heading "*Industry Conditions*";

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

"**UNFCCC**" has the meaning ascribed thereto under the heading "*Industry Conditions*";

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

"**Updated Action Plan**" has the meaning ascribed thereto under the heading "*Industry Conditions*"; and

"**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, 2015 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 Annual Information Form, 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 (unless otherwise stated) Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices) |
| 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 Annual Information Form references to "dollars" and "$" are to the currency of Canada, unless otherwise indicated.

## NON-IFRS MEASURES

This Annual Information Form contains the term "netback" which is not defined by IFRS and therefore may not be comparable to performance measures presented by others. In this Annual Information Form, "netback" is calculated by deducting royalties paid and production costs, including transportation costs, from prices received, excluding the effects of hedging. Operating netback represents revenue less royalties, operating expenses and transportation expenses and has been presented on a per Boe 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. 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 indicators of the Corporation's performance.

Further, reference is made to funds from operations which does not have a standardized meaning as prescribed by generally accepted accounting principles (GAAP) codified by IFRS. Funds from operations may not be comparable to the calculation of similar amounts for other entities. Funds from operations is not intended to represent, or be equivalent to, cash from operating activities calculated in accordance with IFRS. Funds from operations denotes cash flow from operating activities as it appears in the Corporation's statement of cash flows before decommissioning expenditures and changes in non-cash working capital.

## 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" 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;
- 2016 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 levels;
- 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 caveats 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.**

**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.

## 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 – 3$^{rd}$ Street S.W., Calgary, Alberta, T2P 5C5, and its head and principal office is located at 200, 640 – 5$^{th}$ 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, 2013 to December 31, 2015 the Corporation has grown its business by acquiring land, either freehold or Crown, and drilling, completing and equipping wells primarily in east central Alberta. Set out below is a review of the Corporation's activities during such three year period.

***2013***

*Overview of Capital Expenditure Program*

During the year ended December 31, 2013, the Corporation executed a $2.9 million capital program and drilled four gross (2.7 net) wells in the Klein North and Klein South areas of Alberta. Average production for the year was 122 Boe/d.

*General Business Developments*

On December 27, 2013, the Corporation completed a non-brokered private placement of 1,333,333 Common Shares issued on a "flow-through" basis pursuant to the Income Tax Act (Canada) ("**Flow-Through Shares**") at an issue price of $0.75 per Flow-Through Share for aggregate gross proceeds of $1.0 million.

***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 Klein North, Klein 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 Klein 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 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 Klein North area. Additionally, the Corporation acquired freehold and Crown leases in 16 sections of land in a new 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. 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 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 up to seven gross (6.4 net) horizontal wells targeting the Upper Mannville Formation.

**Recent Developments**

On March 31, 2016, the Corporation confirmed its 2016 capital budget to be $11.0 million, which is at the high end of the range provided on November 23, 2015. The capital budget is weighted to the second half of 2016 and drilling is expected to commence after break-up to take advantage of lower costs associated with drilling during the summer months. The drilling program includes three gross (3.0 net) wells in the Klein North area, two gross (1.4 net) wells in the Wildmere area and two gross (2.0 net) wells to evaluate a new area for total drilling, completion, equipping and tie-in capital of $8.7 million. In addition, up to $1.5 million will be allocated to acquiring undeveloped land and seismic, and $0.8 million will be allocated to infrastructure costs related to the initiation of a waterflood in the Klein North area as well as other corporate costs.

**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 Annual Information Form.

### Principal Properties

*Klein North Area*

The Klein North area of east central Alberta is located approximately 20 kilometers south of Provost, Alberta. Altura currently holds a 100% working interest in 640 acres of land in the Klein North area, of which 160 acres are undeveloped and 480 acres are developed. Altura acquired its assets in the Klein North area through a Crown land sale. Altura drilled one well in the area in 2015 which was brought on-stream in the fourth quarter of 2015. The Corporation's exploration, development and production activities in the Klein North area are directed towards medium gravity oil in the Sparky Formation.

McDaniel assigned approximately 498.9 MBOE of proved reserves and 940.3 MBOE of proved plus probable reserves in the Klein North area in the McDaniel Report.

During the year ended December 31, 2015, Altura had average production of approximately 269 Boe/d (including 238 Bbls/d of oil and liquids and 197 Mcf/d of natural gas) from five gross (5.0 net) producing wells in the Klein North 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 the 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 Klein North area.

*Klein South Area*

The Klein 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 Klein 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 Klein South area are directed towards medium gravity oil in the Sparky Formation.

McDaniel assigned approximately 58.8 MBOE of proved reserves and 107.5 MBOE of proved plus probable reserves in the Klein South area in the McDaniel Report.

During the year ended December 31, 2015, Altura had average production of approximately 40 Bbls/d (100% crude oil) from five gross (3.2 net) producing wells in the Klein South area. All of the 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 the sales point.

*Wildmere Area*

The Wildmere area of east central Alberta is located approximately 40 kilometers north of Wainwright, Alberta. Altura currently holds a 60% working interest in 2,080 gross (1,248 net) acres of land in the Wildmere area, of which 480 gross (312 net) acres are undeveloped and 1,600 gross (936 net) acres are developed. The Corporation's exploration, development and production activities in the Wildmere area are directed towards medium gravity oil in the Sparky Formation, which has been defined with vertical wells and 3-D seismic.

McDaniel assigned approximately 102.1 MBOE of proved reserves and 234.7 MBOE of proved plus probable reserves in the Wildmere area in the McDaniel Report.

During the year ended December 31, 2015, Altura had minimal production in the area from one gross (1.0 net) vertical oil well that was reactivated in the fourth quarter of 2015.

*Provost Minors Area*

The Provost Minors area consists of a number of properties located around Provost, Alberta. Altura currently holds a 72% working interest in 26,861 gross (19,342 net) acres of land in the area, of which 12,450 gross (11,650 net) acres are undeveloped and 14,411 gross (7,692 net) acres are developed. Oil gravity is in the range of 20° to 28° API for the upper Mannville targets in the area.

McDaniel assigned approximately 65.1 MBOE of proved reserves and 79.9 MBOE of proved plus probable reserves in the Provost Minors area in the McDaniel Report.

During the year ended December 31, 2015, Altura had average production of approximately 39 Boe/d (including 31 Bbls/d of oil and liquids and 45 Mcf/d of natural gas) from six gross (6.0 net) operated wells and 2 gross (0.5 net) non-operated wells in the area. All of the production in the area is tied into single well batteries.

**Personnel**

The Corporation currently has five 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 is capable of growing 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 available to it various specialized consultants to assist it 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 are able to 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 Annual Information Form, 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, 2015 and a preparation date of March 9, 2016. 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 Annual Information Form. 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, 2015 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, 2015

| Reserves Category | Light and Medium Crude Oil Gross[1] (Mbbl) | Light and Medium Crude Oil Net[2] (Mbbl) | Heavy Crude Oil Gross[1] (Mbbl) | Heavy Crude Oil Net[2] (Mbbl) | Conventional Natural Gas Gross[1] (MMcf) | Conventional Natural Gas Net[2] (MMcf) | Natural Gas Liquids Gross[1] (Mbbl) | Natural Gas Liquids Net[2] (Mbbl) | Total Oil Equivalent Gross[1] (Mboe) | Total Oil Equivalent Net[2] (Mboe) |
|---|---|---|---|---|---|---|---|---|---|---|
| **PROVED** | | | | | | | | | | |
| Developed Producing | 360.2 | 325.1 | 18.4 | 17.5 | 301.4 | 286.7 | 5.1 | 3.5 | 433.9 | 394.0 |
| Developed Non-Producing | - | - | - | - | - | - | - | - | - | - |
| Undeveloped | 184.7 | 168.5 | 83.7 | 77.3 | 122.4 | 116.2 | 2.2 | 1.6 | 291.0 | 266.8 |
| **TOTAL PROVED** | 544.9 | 493.7 | 102.1 | 94.8 | 423.8 | 403.0 | 7.2 | 5.1 | 724.9 | 660.7 |
| **TOTAL PROBABLE** | 446.5 | 393.9 | 132.6 | 118.7 | 317.7 | 301.7 | 5.4 | 3.9 | 637.5 | 566.7 |
| **TOTAL PROVED & PROBABLE** | 991.4 | 887.6 | 234.7 | 213.5 | 741.5 | 704.7 | 12.7 | 9.0 | 1,362.4 | 1,227.5 |

**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, 2015

| Reserves Category | Before Income Taxes Discounted at (%/year) 0% (MM$) | 5% (MM$) | 10% (MM$) | 15% (MM$) | 20% (MM$) | After Income Taxes Discounted at (%/year) 0% (MM$) | 5% (MM$) | 10% (MM$) | 15% (MM$) | 20% (MM$) | Unit Value Before Tax @10%[1] ($/BOE) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **PROVED** | | | | | | | | | | | |
| Developed Producing | 10.3 | 9.2 | 8.2 | 7.4 | 6.8 | 10.3 | 9.2 | 8.2 | 7.4 | 6.8 | 20.81 |
| Developed Non-Producing | - | - | - | - | - | - | - | - | - | - | - |
| Undeveloped | 5.5 | 4.3 | 3.3 | 2.6 | 2.1 | 5.4 | 4.2 | 3.3 | 2.6 | 2.1 | 12.50 |
| **TOTAL PROVED** | 15.8 | 13.4 | 11.5 | 10.1 | 8.9 | 15.7 | 13.4 | 11.5 | 10.1 | 8.9 | 17.46 |
| **TOTAL PROBABLE** | 17.3 | 12.6 | 9.5 | 7.4 | 5.9 | 12.6 | 9.2 | 6.9 | 5.4 | 4.3 | 16.69 |
| **TOTAL PROVED & PROBABLE** | 33.1 | 26.0 | 21.0 | 17.4 | 14.8 | 28.3 | 22.6 | 18.4 | 15.5 | 13.2 | 17.10 |

**Note:**

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

## TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
## FORECAST PRICES AND COSTS AS OF DECEMBER 31, 2015

| 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 | 44,805 | 3,979 | 19,217 | 3,993 | 1,801 | 15,815 | 72 | 15,743 |
| TOTAL PROVED & PROBABLE | 90,738 | 9,131 | 36,960 | 9,158 | 2,392 | 33,097 | 4,795 | 28,302 |

**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, 2015

| 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) | 10,651 | 21.58 |
| | Heavy Crude Oil (Including Solution Gas and By-products) | 910 | 9.60 |
| | Conventional Natural Gas (Including By-products) | (27) | (0.89) |
| | **TOTAL** | **11,534** | |
| TOTAL PROVED & PROBABLE | Light and Medium Crude Oil (Including Solution Gas and By-products) | 18,421 | 20.75 |
| | Heavy Crude Oil (Including Solution Gas and By-products) | 2,586 | 12.12 |
| | Conventional Natural Gas (Including By-products) | (14) | (0.30) |
| | **TOTAL** | **20,994** | |

**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, 2015 in the McDaniel Report in estimating reserves data using forecast prices and costs. Benchmark weighted average historical prices for 2015 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 |
| 2015 | 48.85 | 57.70 | 44.95 | 39.80 | 2.80 | 60.65 | 35.55 | 0.0 | 0.780 |
| Forecast(4) | | | | | | | | | |
| 2016 | 45.00 | 56.60 | 46.40 | 40.50 | 2.70 | 60.60 | 35.20 | 0.0 | 0.730 |
| 2017 | 53.60 | 66.40 | 54.40 | 47.50 | 3.20 | 70.50 | 41.30 | 2.0 | 0.750 |
| 2018 | 62.40 | 72.80 | 59.70 | 52.10 | 3.55 | 77.00 | 48.00 | 2.0 | 0.800 |
| 2019 | 69.00 | 80.90 | 66.30 | 57.80 | 3.85 | 85.10 | 56.30 | 2.0 | 0.800 |
| 2020 | 73.10 | 83.20 | 68.20 | 59.50 | 3.95 | 87.50 | 61.00 | 2.0 | 0.825 |
| 2021 | 77.30 | 88.20 | 72.30 | 63.10 | 4.20 | 92.60 | 64.60 | 2.0 | 0.825 |
| 2022 | 81.60 | 93.30 | 76.50 | 66.70 | 4.45 | 97.80 | 68.40 | 2.0 | 0.825 |
| 2023 | 86.20 | 98.70 | 80.90 | 70.60 | 4.70 | 103.30 | 72.30 | 2.0 | 0.825 |
| 2024 | 87.90 | 100.70 | 82.60 | 72.00 | 4.80 | 105.40 | 73.80 | 2.0 | 0.825 |
| 2025 | 89.60 | 102.60 | 84.10 | 73.40 | 4.90 | 107.40 | 75.20 | 2.0 | 0.825 |
| 2026 | 91.40 | 104.70 | 85.90 | 74.90 | 5.00 | 109.60 | 76.70 | 2.0 | 0.825 |
| 2027 | 93.30 | 106.90 | 87.70 | 76.40 | 5.10 | 111.90 | 78.30 | 2.0 | 0.825 |
| 2028 | 95.10 | 108.90 | 89.30 | 77.90 | 5.20 | 114.00 | 79.80 | 2.0 | 0.825 |
| 2029 | 97.00 | 111.10 | 91.10 | 79.40 | 5.30 | 116.30 | 81.40 | 2.0 | 0.825 |
| 2030 | 99.00 | 113.40 | 93.00 | 81.10 | 5.40 | 118.70 | 83.10 | 2.0 | 0.825 |
| Thereafter | +2.0%/yr | +2.0%/yr | +2.0%/yr | +2.0%/yr | +2.0%/yr | +2.0%/yr | +2.0%/yr | 2.0 | 0.825 |

**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, 2015, derived from the McDaniel Report using forecast prices and cost estimates, reconciled to the Corporation's gross reserves as at December 31, 2014.

### 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, 2014 | 1,398.9 | 1,615.3 | 3,014.2 | 526.5 | 504.8 | 1,031.3 | 2,493.8 | 2,341.2 | 4,835.0 |
| Extensions & Improved Recovery | - | - | - | - | - | - | - | - | - |
| Technical Revisions(1) | (724.6) | (1,159.8) | (1,884.4) | (421.6) | (371.1) | (792.8) | (1,944.1) | (2,015.0) | (3,959.1) |
| Discoveries | - | - | - | - | - | - | - | - | - |
| Acquisitions | - | - | - | - | - | - | - | - | - |
| Dispositions | - | - | - | - | - | - | - | - | - |
| Economic Factors(2) | (17.1) | (9.0) | (26.1) | (2.6) | (1.1) | (3.7) | (21.1) | (8.5) | (29.6) |
| Production | (112.3) | - | (112.3) | (0.2) | - | (0.2) | (104.8) | - | (104.8) |
| December 31, 2015 | 544.9 | 446.5 | 991.4 | 102.1 | 132.6 | 234.7 | 423.8 | 317.7 | 741.5 |

| | Natural Gas Liquids | | | Total Oil Equivalent | | |
|---|---|---|---|---|---|---|
| **FACTORS** | **Proved (Mbbl)** | **Probable (Mbbl)** | **Proved & Probable (Mbbl)** | **Proved (Mboe)** | **Probable (Mboe)** | **Proved & Probable (Mboe)** |
| December 31, 2014 | 50.4 | 66.4 | 116.8 | 2,391.4 | 2,576.7 | 4,968.2 |
| Extensions & Improved Recovery | - | - | - | - | - | - |
| Technical Revisions(1) | (40.9) | (60.8) | (101.7) | (1,487.3) | (1,916.0) | (3,403.4) |
| Discoveries | - | - | - | - | - | - |
| Acquisitions | - | - | - | - | - | - |
| Dispositions | - | - | - | - | - | - |
| Economic Factors(2) | (0.2) | (0.1) | (0.3) | (23.4) | (11.6) | (35.0) |
| Production | (2.1) | - | (2.1) | (132.0) | - | (132.0) |
| December 31, 2015 | 7.2 | 5.5 | 12.7 | 724.9 | 637.5 | 1,362.4 |

**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** |
| 2013 | 173.2 | - | - | 8.1 |
| 2014 | 214.5 | 86.9 | 149.9 | - |
| 2015 | - | - | - | - |

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 291 MBOE of proved undeveloped reserves in the McDaniel Report with $4.0 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.

| Year | Light and Medium Crude Oil (Mbbl) First Attributed | Heavy Crude Oil (Mbbl) First Attributed | Conventional Natural Gas (MMcf) First Attributed | Natural Gas Liquids (Mbbl) First Attributed |
|---|---|---|---|---|
| 2013 | 373.4 | - | - | 7.2 |
| 2014 | 101.9 | 188.6 | - | 29.7 |
| 2015 | - | - | - | - |

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 509.6 MBOE of probable undeveloped reserves in the McDaniel Report with $5.2 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, however, 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 are 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 $2.45 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 $0.31 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, 2015 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).

| ($000s) | FORECAST PRICES AND COSTS<br>Total Proved Reserves | <br>Total Proved Plus Probable Reserves |
|---|---|---|
| 2016 | 2,200 | 2,200 |
| 2017 | 1,283 | 3,496 |
| 2018 | 510 | 3,462 |
| 2019 | - | - |
| 2020 | - | - |
| Thereafter | - | - |
| Total for all years undiscounted | 3,993 | 9,158 |
| Total for all years discounted at 10% per year | 3,556 | 7,832 |

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.

## 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, 2015.

| | Oil Wells | | | | Natural Gas Wells | | | |
|---|---|---|---|---|---|---|---|---|
| | Producing | | Non-Producing | | Producing | | Non-Producing | |
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net |
| Alberta | 18 | 14.7 | 8 | 6.5 | 2 | 2.0 | 21 | 11.8 |
| British Columbia | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0.3 |
| Total | 18 | 14.7 | 8 | 6.5 | 2 | 2.0 | 22 | 12.1 |

**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 2015 that were capable of production and had reserves assigned to them.

## Properties with no Attributed Reserves

The following table summarizes, effective December 31, 2015, 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 | 26,793 | 24,973 | 1,600 |
| Total | 26,793 | 24,973 | 1,600 |

## 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 funds from operations are 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 better 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 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 at least 2018. See "*Risk Factors – Income Taxes*".

### Costs Incurred

The following table summarizes capital expenditures incurred by the Corporation during the year ended December 31, 2015.

| | Property Acquisitions | | | |
|---|---|---|---|---|
| **($000s)** | **Proved Properties** | **Unproved Properties** | **Exploration Costs** | **Development Costs** |
| Total | 251 | - | 1,061 | 1,892 |

### 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, 2015. All wells were drilled in Canada.

| | Exploratory Wells | | Development Wells | |
|---|---|---|---|---|
| | **Gross** | **Net** | **Gross** | **Net** |
| Light and Medium Crude Oil | - | - | 1 | 1.0 |
| Natural Gas | - | - | - | - |
| Service | - | - | - | - |
| Stratigraphic Test | - | - | - | - |
| Dry | - | - | - | - |
| Total | - | - | 1 | 1.0 |

### Planned Capital Expenditures

In March 2016 Altura announced its planned capital expenditure budget of $11.0 million for 2016 which is primarily focused on upper Mannville medium grade oil projects with the majority of the capital directed to drilling, completions and tie-ins (approximately 79%). This capital budget is weighted to the second half of 2016 and drilling is expected to commence after break-up to take advantage of lower costs associated with drilling during the summer months. The drilling program includes three (3.0 net) wells in the Klein North area, two (1.4 net) wells in the Wildmere area and two (2.0 net) wells to evaluate a new area.

With the current volatility of commodity prices, Altura continues to actively monitor the 2016 capital expenditure plans in the context of expected funds from operations, 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 2016 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 | 259 | 8 | 269 | 4 | 316 |
| Developed Non-Producing | - | - | - | - | - |
| Undeveloped | 73 | - | 56 | 1 | 83 |
| **TOTAL PROVED** | 332 | 8 | 325 | 5 | 400 |
| **TOTAL PROBABLE** | 21 | - | 20 | - | 25 |
| **TOTAL PROVED & PROBABLE** | 353 | 8 | 345 | 5 | 425 |

The estimated production volumes for the Klein North property, which accounts for more than 80% of McDaniel's total forecast production for the year ending December 31, 2016, is set forth below.

| | Klein North Total Oil Equivalent BOE/d |
|---|---|
| **PROVED** | |
| Developed Producing | 243 |
| Developed Non-Producing | - |
| Undeveloped | 83 |
| **TOTAL PROVED** | 326 |
| **TOTAL PROBABLE** | 23 |
| **TOTAL PROVED & PROBABLE** | 349 |

## Production History

The following table discloses, on a quarterly basis for the year ended December 31, 2015, certain information in respect of the Corporation's production, product prices received, royalties paid, operating expenses and resulting netback by product type.

| | Quarter Ended 2015 | | | | Year Ended Dec. 31, 2015 |
|---|---|---|---|---|---|
| | **Mar. 31** | **Jun. 30** | **Sep. 30** | **Dec. 31** | |
| **Average Daily Production**[1] | | | | | |
| Light and Medium Crude Oil (Bbl/d)[2] | 389 | 310 | 299 | 355 | 338 |
| Heavy Crude Oil (Bbl/d) | 4 | 3 | 4 | 7 | 4 |
| Conventional Natural Gas (Mcfe/d) [3] | 75 | 73 | 148 | 161 | 115 |
| Combined (BOE/d) | 405 | 325 | 328 | 389 | 361 |
| **Average Net Production Prices Received** | | | | | |
| Light and Medium Crude Oil ($/Bbl) [2] | 40.99 | 54.49 | 42.65 | 36.91 | 43.36 |
| Heavy Crude Oil ($/Bbl) | 38.85 | 48.11 | 37.40 | 29.86 | 36.51 |
| Conventional Natural Gas ($/Mcfe) [3] | 6.15 | 4.68 | 3.84 | 3.41 | 4.20 |
| Combined ($/BOE) | 40.84 | 53.44 | 41.12 | 35.66 | 42.32 |
| **Royalties Paid** | | | | | |
| Light and Medium Crude Oil ($/Bbl) [2] | 1.85 | 2.23 | 2.00 | 1.41 | 1.85 |
| Heavy Crude Oil ($/Bbl) | - | - | - | - | - |
| Conventional Natural Gas ($/Mcfe) [3] | 0.65 | 0.42 | 0.22 | 0.22 | 0.32 |
| Combined ($/BOE) | 1.90 | 2.22 | 1.93 | 1.37 | 1.84 |
| **Production Costs** | | | | | |
| Light and Medium Crude Oil ($/Bbl) [2] | 10.47 | 14.86 | 14.90 | 12.12 | 12.90 |
| Heavy Crude Oil ($/Bbl) | 131.46 | 78.53 | 39.61 | 42.07 | 66.99 |
| Conventional Natural Gas ($/Mcfe) [3] | 3.28 | 5.22 | 2.52 | 2.21 | 2.96 |
| Combined ($/BOE) | 11.87 | 16.05 | 15.19 | 12.73 | 13.80 |
| **Netback Received ($/BOE)**[4] | | | | | |
| Light and Medium Crude Oil ($/Bbl) [2] | 28.67 | 37.40 | 25.75 | 23.38 | 28.61 |
| Heavy Crude Oil ($/Bbl) | (92.61) | (30.42) | (2.21) | (12.21) | (30.48) |
| Conventional Natural Gas ($/Mcfe) [3] | 2.22 | (0.96) | 1.10 | 0.99 | 0.91 |
| Combined ($/BOE) | 27.07 | 35.17 | 24.00 | 21.56 | 26.68 |

**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, 2015.

| | 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 | | | | | | |
| Klein North | 234 | - | 4 | 197 | 269 | 75 |
| Klein South | 40 | - | - | - | 40 | 11 |
| Provost Minor | 27 | 3 | - | 45 | 38 | 11 |
| Bowden | 3 | - | 2 | 45 | 13 | 4 |
| Wildmere | - | 1 | - | - | 1 | - |
| Total | 304 | 4 | 6 | 287 | 361 | 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(4) | Position Held | Date First Elected or Appointed |
|---|---|---|
| David Burghardt<br>Calgary, Alberta | President, Chief Executive Officer and Director | July 31, 2015 |
| Tavis Carlson<br>Calgary, Alberta | Vice-President, Finance and Chief Financial Officer and Secretary | September 1, 2015 |
| Travis Stephenson<br>Calgary, Alberta | Vice-President, Engineering | July 31, 2015 |
| Robert Pinckston<br>Calgary, Alberta | Vice-President, Exploration | July 31, 2015 |
| Jeff Mazurak<br>Calgary, Alberta | Vice-President, Operations | July 31, 2015 |
| John McAleer(1)(3)<br>Calgary, Alberta | Director | July 31, 2015 |
| Brian Lavergne(2)(3)<br>Calgary, Alberta | Director | July 31, 2015 |
| Darren Gee(1)(2)<br>Calgary, Alberta | Director | July 31, 2015 |
| Robert Maitland(1)(3)<br>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.
(4) Maureen Keough held the position of Vice-President, Land from July 31, 2015 until April 4, 2016.

As at the date hereof, the officers and directors, as a group, held, directly or indirectly, or exercise control or direction over 10,332,899 Common Shares representing 9.49% 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 29 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.

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

Mr. Carlson is a Chartered Accountant with 14 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 16 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 the Association of Professional Engineers and Geoscientists of Alberta ("**APEGA**").

**Robert Pinckston, Vice-President, Exploration**

Mr. Pinckston has 27 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 12 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.

**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 25 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., Institutional Research with FirstEnergy Capital Corp., and Manager, Gas Projects with Renaissance Energy Ltd. ("**Renaissance**"). He earned a BASc 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 a director of Perpetual Energy Inc. and Rock 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, 2015; (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, 2015.

### Interest of Management and Others in Material Transactions

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

## DIVIDENDS AND DISTRIBUTIONS

The Corporation has not declared or 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, 2015 and as at April 29, 2016, 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, 2015 the Corporation had outstanding a total of 3,950,000 Options to purchase Common Shares to its directors and officers exercisable at a price of $0.3375 per Common Share with expiry dates ending November 30, 2020. As at the date hereof, the Corporation had outstanding a total of 3,450,000 Options. At April 29, 2016, no Options have yet vested.

**Warrants**

As at December 31, 2015, the Corporation had 102,239,529 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 April 29, 2016, 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, 2015 to December 31, 2015.

| Month | High ($) | Low ($) | Volume |
|---|---|---|---|
| January 2015 | 0.70 | 0.45 | 68,664 |
| February 2015 | 0.50 | 0.45 | 135,810 |
| March 2015 | 0.50 | 0.40 | 215,547 |
| April 2015 | 0.45 | 0.35 | 19,442 |
| May 2015 | 0.50 | 0.40 | 75,043 |
| June 2015 | 0.55 | 0.40 | 472,985 |
| July 2015 | 0.55 | 0.45 | 207,341 |
| August 2015 | 0.55 | 0.40 | 142,220 |
| September 2015 | 0.60 | 0.40 | 177,423 |
| October 2015 | 0.50 | 0.40 | 204,971 |
| November 2015 | 0.445 | 0.33 | 99,296 |
| December 2015 | 0.40 | 0.31 | 125,674 |

During the financial year ended December 31, 2015, the Corporation granted: (i) an aggregate of 102,239,529 Performance Warrants (exercisable for up to 10,223,953 Common Shares at an exercise price of $0.449 per Common Share); and (ii) an aggregate of 3,950,000 Options with an exercise price of $0.3375 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

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government and with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada and Alberta all of which should be carefully considered by investors in the oil and natural gas industry. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and natural gas industry in western Canada.

**Pricing and Marketing**

***Oil***

In Canada, the producers of oil are entitled to negotiate sales contracts directly with oil purchasers, which results in the market determining the price of oil. Worldwide supply and demand factors primarily determine oil prices; however, prices are also influenced by geopolitical conflicts and regional market and transportation issues. The specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, the supply/demand balance and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (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. The NEB is currently undergoing a consultation process to update the regulations governing the issuance of export licenses. The updating process is necessary to meet the criteria set out in the federal Jobs, Growth and Long-term Prosperity Act (Canada) (the "**Prosperity Act**") which received Royal Assent on June 29, 2012. In this transitory period, the NEB has issued, and is currently following an "Interim Memorandum of Guidance concerning Oil and Gas Export Applications and Gas Import Applications" under Part VI of the *National Energy Board Act* (Canada).

***Natural Gas***

Canada's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system, at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange, Intercontinental Exchange or the New York Mercantile Exchange in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m3/day) must be made pursuant to a NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 40 years) or for a larger quantity requires an exporter to obtain an export license from the NEB.

## The North American Free Trade Agreement

NAFTA among the governments of Canada, the United States and Mexico came into force on January 1, 1994. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply.

All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings. NAFTA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports. NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes.

## Trans-Pacific Partnership

On October 5, 2015, Canada and 11 other countries announced an agreement in respect of the Trans-Pacific Partnership ("**TPP**"). Canada and each participating country must also ratify the TPP in their national legislatures. The TPP is the most ambitious trade initiative in the Asia-Pacific region. The TPP would lower tariffs on a wide range of Canadian products and benefit exporters across Canada in a number of sectors, including agriculture, wood and wood products, chemicals and plastics, and fish and seafood. An agreement would also bring enhanced and more predictable market access for Canada's services providers.

## Royalties and Incentives

### *General*

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

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are generally introduced when commodity prices are low to encourage exploration and development activity by improving earnings and cash flow within the industry.

***Alberta***

Currently, producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced.

In 2016, the provincial government of Alberta announced the key highlights of a proposed Modernized Royalty Framework ("**MRF**") that will be effective on January 1, 2017. These highlights include providing royalty incentives for the efficient development of conventional crude oil, natural gas and NGL resources, no changes to the royalty structure of wells drilled prior to 2017 for a 10-year period from the royalty program's implementation date, the replacement of royalty credits and holidays on conventional wells by a revenue minus cost framework with a post-payout royalty rate based on commodity prices, the reduction of royalty rates for mature wells, and a neutral internal rate of return for any given play compared to the current royalty framework. Details of the MRF calibration formulas have been released and more specific information will be provided by the provincial government in the coming months to help crude oil and natural gas producers better understand the economics of investment in Alberta.

Royalties are currently paid pursuant to "The New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) and the "Alberta Royalty Framework", which was implemented in 2010. Royalty rates for conventional oil are set by a single sliding rate formula, which is applied monthly and incorporates separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime is 40%. Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula with the maximum royalty payable under the royalty regime set at 36%.

Producers of oil and natural gas from freehold lands in Alberta are required to pay freehold mineral tax. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands and is derived from the *Freehold Mineral Rights Tax Act* (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. The basic formula for the assessment of freehold mineral tax is: revenue less allocable costs equals net revenue divided by wellhead production equals the value based upon unit of production. If payors do not wish to file individual unit values, a default price is supplied by the Crown. On average, the tax levied is 4% of revenues reported from fee simple mineral title properties.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and natural gas development and new drilling. For example, the Innovative Energy Technologies Program has the stated objectives of increasing recovery from oil and natural gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The Innovative Energy Technologies Program provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources. These initiatives apply to wells drilled before January 1, 2017, for a 10 year period, until January 1, 2027. Specifically:

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;

- Shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;

- Horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and

- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

While the MRF eliminates the various royalty credits and incentives, outlined above, for wells drilled after December 31, 2016, the Government of Alberta has committed to creating cost allowance programs for both enhanced oil recovery schemes and higher risk experimental drilling.

**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.

**Production and Operation Regulations**

The oil and natural gas industry in Canada is highly regulated and subject to significant control by provincial regulators. Regulatory approval is required for, among other things, the drilling of oil and natural gas wells, construction and operation of facilities, the storage, injection and disposal of substances and the abandonment and reclamation of well-sites. In order to conduct oil and natural gas operations and remain in good standing with the applicable provincial regulator, the Corporation must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance with such legislation, regulations, orders, directives or other directions can be costly and a breach of the same may result in fines or other sanctions.

**Environmental Regulation**

The oil and natural gas industry is currently subject to regulation pursuant to a variety of provincial and federal environmental legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and natural gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability and the imposition of material fines and penalties.

### *Federal*

Pursuant to the Prosperity Act, the Government of Canada amended or repealed several pieces of federal environmental legislation and in addition, created a new federal environment assessment regime that came in to force on July 6, 2012. The changes to the environmental legislation under the *Prosperity Act* are intended to provide for more efficient and timely environmental assessments of projects that previously had been subject to overlapping legislative jurisdiction.

### *Alberta*

The Alberta Energy Regulator (the "**AER**") is the single regulator responsible for all energy development in Alberta. The AER ensures the safe, efficient, orderly, and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind a single regulator is an enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

The Government of Alberta relies on regional planning to accomplish its responsible resource development goals. The following frameworks, plans and policies form the basis of Alberta's Integrated Resource Management System. The Integrated Resource Management System method to natural resource management sets out to engage and consult with stakeholders and the public. While the AER is the primary regulator for energy development, several governmental departments and agencies may be involved in land use issues, including Alberta Environment and Parks, Alberta Energy, the AER, the Alberta Environmental Monitoring, Evaluation and Reporting Agency, the Policy Management Office, the Aboriginal Consultation Office, and the Land Use Secretariat.

In December 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of seven region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans.

Proclaimed in force in Alberta on October 1, 2009, the Alberta Land Stewardship Act (the "**ALSA**") provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established under the ALSA are deemed to be legislative instruments equivalent to regulations and will be binding on the Government of Alberta and provincial regulators, including those governing the oil and natural gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, licenses, registrations, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment.

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("**LARP**") which came into force on September 1, 2012. The LARP is the first of seven regional plans developed under the ALUF. LARP covers a region in the northeastern corner of Alberta that is approximately 93,212 square kilometres in size. The region includes a substantial portion of the Athabasca oil sands area, which contains approximately 82% of the province's oil sands resources and much of the Cold Lake oil sands area. LARP establishes six new conservation areas and nine new provincial recreation areas. In conservation and provincial recreation areas, conventional oil and natural gas companies with pre-existing tenure may continue to operate. Any new petroleum and gas tenure issued in conservation and provincial recreation areas will include a restriction that prohibits surface access. In contrast, oil sands companies' tenure has been (or will be) cancelled in conservation areas and no new oil sands tenure will be issued. While new oil sands tenure will be issued in provincial recreation areas, new and existing oil sands tenure will prohibit surface access.

In July 2014, the Government of Alberta approved the South Saskatchewan Regional Plan ("**SSRP**") which came into force on September 1, 2014. The SSRP is the second regional plan developed under the ALUF. The SSRP covers approximately 83,764 square kilometres and includes 44% of the provincial population. The SSRP creates four new and four expanded conservation areas, and two new and six expanded provincial parks and recreational areas. Similar to LARP, the SSRP will honour existing petroleum and natural gas tenure in conservation and provincial recreational areas. However, any new petroleum and natural gas tenures sold in conservation areas, provincial parks, and recreational areas will prohibit surface access. However, oil and natural gas companies must minimize impacts of activities on the natural landscape, historic resources, wildlife, fish and vegetation when exploring, developing and extracting the resources. Freehold mineral rights will not be subject to this restriction.

**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.

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.

**Climate Change Regulation**

***Federal***

Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulatory environment of the oil and natural gas industry in Canada. Such regulations, surveyed below, impose certain costs and risks on the industry.

The Government of Canada is a signatory to the *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and a participant to the Copenhagen Accord (a non-binding agreement created by the UNFCCC which represents a broad political consensus and reinforces commitments to reducing greenhouse gas ("**GHG**") emissions). On January 29, 2010, Canada inscribed in the Copenhagen Accord its 2020 economy-wide target of a 17% reduction of GHG emissions from 2005 levels. This target is aligned with the United States target. In a report dated October 2013, the federal government stated that this target represents a significant challenge in light of strong economic growth (Canada's economy is projected to be approximately 31% larger in 2020 compared to 2005 levels).

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on

March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets, for application to regulated sectors on a facility-specific basis, sector-wide basis or company-by-company basis. Although the intention was for draft regulations aimed at implementing the Updated Action Plan to become binding on January 1, 2010, the only regulations being implemented are in the transportation and electricity sectors. The federal government indicates that it is taking a sector-by-sector regulatory approach to reducing GHG emissions and is working on regulations for other sectors. Representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. In June 2012, the second US-Canada Clean Energy Dialogue Action Plan was released. The plan renewed efforts to enhance bilateral collaboration on the development of clean energy technologies to reduce GHG emissions.

On December 12, 2015, the UNFCCC adopted the Paris Agreement, to which Canada is a participant. The Paris Agreement mandates that all countries must work together to limit global temperature rise resulting from GHG emissions to a goal of less than 2° Celsius and to pursue efforts to limit below 1.5° Celsius, through implementing successive nationally determined contributions.

***Alberta***

As part of its efforts to reduce GHG emissions, Alberta introduced legislation to address GHG emissions: the *Climate Change and Emissions Management Act* enacted on December 4, 2003 and amended through the *Climate Change and Emissions Management Amendment Act*, which received royal assent on November 4, 2008. The accompanying regulations include the *Specified Gas Emitters Regulation* ("**SGER**"), which imposes GHG limits, and the *Specified Gas Reporting Regulation*, which imposes GHG emissions reporting requirements. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their GHG emissions. The SGER applies to facilities emitting more than 100,000 tonnes of GHGs in 2003 or any subsequent year ("**Regulated Emitters**") and requires reductions in GHG emissions intensity (e.g. the quantity of GHG emissions per unit of production) from emissions intensity baselines established in accordance with the SGER.

On June 25, 2015, the Government of Alberta renewed the SGER for a period of two years with significant amendments while Alberta's newly formed Climate Advisory Panel conducted a comprehensive review of the province's climate change policy. In 2015, Regulated Emitters are required to reduce their emissions intensity by 2% from their baseline in the fourth year of commercial operation, 4% of their baseline in the fifth year, 6% of their baseline in the sixth year, 8% of their baseline in the seventh year, 10% of their baseline in the eighth year, and 12% of their baseline in the ninth or subsequent years. These reduction targets will increase, meaning that Regulated Emitters in their ninth or subsequent years of commercial operation must reduce their emissions intensity from their baseline by 15% in 2016 and 20% in 2017.

Regulated Emitters can meet their emissions intensity targets through a combination of the following: (1) producing its products with lower carbon inputs, (2) purchasing emissions offset credits from non-regulated emitters (generated through activities that result in emissions reductions in accordance with established protocols), (3) purchasing emissions performance credits from other Regulated Emitters that earned credits through the reduction of their emissions below the 100,000 tonne threshold, (4) cogeneration compliance adjustments, and (5) by contributing to the Climate Change and Emissions Management Fund (the "**Fund**"). Contributions to the Fund are made at a rate of $15 per tonne of GHG emissions, increasing to a rate of $20 per tonne of GHG emissions in 2016 and $30 per tonne of GHG emissions in 2017. Proceeds from the Fund are directed at testing and implementing new technologies for green energy production.

On November 22, 2015, as a result of the Climate Advisory Panel's Climate Leadership report, the Government of Alberta announced its Climate Leadership Plan which proposes to introduce a carbon tax on all emitters. An economy-wide levy $30 per tonne of GHG emissions will be phased in; starting in January 2017 at $20 per tonne and increasing to $30 per tonne in January 2018. An oil sands specific approach was proposed to replace the $30 per tonne of GHG emissions to further reduce emissions and promote carbon competitiveness rather than rewarding past intensity levels. A 100 megatonne per year limit for GHG emissions was proposed for oil sands operations, which currently emit roughly 70 megatonnes per year. This cap exempts new upgrading and cogeneration facilities, which are allocated a separate 10 megatonne limit. The existing SGER will be replaced for large industrial facilities with a Carbon Competitiveness Regulation, in which sector specific output-based carbon allocations will be used to ensure competitiveness.

Alberta is also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed $1.24 billion over 15 years to fund two largescale carbon capture and storage projects that will begin commercializing the technology on the scale needed to be successful. On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*. It deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

## 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.

### 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 due to the current state of the world and national economies, the actions of OPEC or individual producing nations, 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.

**Weakness in the Oil and Gas Industry**

Recent market events and conditions, including global excess oil and natural gas supply, recent actions taken by OPEC, slowing growth in China and other emerging economies, market volatility and disruptions in Asia, and sovereign debt levels in various countries, have caused significant weakness and volatility in commodity prices. These events and conditions have caused a significant decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry. These difficulties have been exacerbated in Canada by the recent changes in government at a federal level and in Alberta at the provincial level, and the resultant uncertainty surrounding regulatory, tax and royalty changes that may be implemented by the new governments. In addition, the inability to get the necessary approvals to build pipelines and other facilities to provide better access to markets for the oil and gas industry in western Canada has led to additional uncertainty and reduced confidence in the oil and gas industry in western Canada. Lower commodity prices may also affect the volume and value of the Corporation's reserves especially as certain reserves become uneconomic. In addition, lower commodity prices have reduced, and are anticipated to continue to reduce, the Corporation's cash flow which could result in a reduced capital expenditure budget. As a result, the Corporation may not be able to replace its production with additional reserves and both the Corporation's production and reserves could be reduced on a year over year basis. Any decrease in value of the Corporation's reserves may reduce the borrowing base under the Credit Facilities, which, depending on the level of the Corporation's indebtedness, could result in the Corporation having to repay a portion of its indebtedness. Given the current market conditions and the lack of confidence in the Canadian oil and gas industry, the Corporation may have difficulty raising additional funds in the future or if it is able to do so, it may be on unfavourable and highly dilutive terms.

**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, 2016. 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 funds from operations, 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.

**Royalties**

Frequent changes to royalty regimes have created uncertainty surrounding the ability to accurately estimate future royalties and, correspondingly, cash flow, resulting in additional volatility and uncertainty for producers including the Corporation.

**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 and Operational Matters**

Many aspects of the oil and natural gas business present environmental risks and hazards, including the risk that the Corporation may be in non-compliance with an environmental law, regulation, or with a necessary permit, licence, or other regulatory approval, possibly unintentionally or without knowledge. Such risks may expose the Corporation to fines or penalties, third party liabilities or to the requirement to remediate, each of which could be material. The operational hazards associated with possible blowouts, accidents, spills, gas leaks, fires, or other damage to a well or a pipeline may require the Corporation to incur costs and delays to undertake corrective actions, and could result in environmental damage or contamination for which the Corporation could be liable for remediation costs and fines imposed by regulatory agencies. Oil and gas operations are also subject to specific operational risks which may have material operational and financial effect on the Corporation should they occur, such as drilling into unexpected formations or unexpected downhole pressures, premature decline of reservoirs, and water invasion into producing formations. In addition, certain of the Corporation’s wells will produce sour gas, which necessitates the use of equipment built to sour gas specifications. In addition to being subject to stringent regulation by the provincial regulator with respect to emergency response plans, public safety and application procedures and requirements, sour gas operations are subject to special control and handling. Although the Corporation maintains liability insurance consistent with prudent industry practice, the nature of environmental risks is such that they may exceed commercially reasonable insurance coverage. In this event the Corporation could incur significant costs which would be funded from cash resources and which may have an adverse effect on the Corporation’s ability to finance future investment or continue in business.

There is currently industry uncertainty as to the potential application and extent of GHG reduction requirements and potential compliance options. As a result, it is not possible to predict the operational and financial effects of future GHG emissions laws, if any, applicable to the Corporation.

**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, 2015 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. The Corporation will attempt to mitigate these risks as follows:

- Properties are developed in areas where there is access to processing and pipeline or other transportation infrastructure, and, where possible, owned by the Corporation.

- The Corporation will delay drilling or tie-in of new wells or shut in production if acceptable pricing cannot be realized.

The Corporation had contracted pipeline transportation capacity for approximately 74% of total natural gas sales volumes in 2015 with the remaining portion relying on access to interruptible capacity. There is a risk that the uncontracted, interruptible portion could be reduced or shut in if capacity is allocated to other parties. To mitigate this risk, the Corporation intends to increase the amount of contracted pipeline transportation.

Pricing and access to markets has been affected by the growth of domestic gas production in the United States. When, if ever, access to historical markets in the United States may improve, is not predictable. Further, development of certain natural gas reserves in Canada is to a degree underwritten by the expectation that new Pacific Rim export markets will be accessed through the establishment of LNG liquefaction facilities on Canada's west coast. When such facilities will be completed, if ever, cannot be predicted.

**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.

**Dependence on Key Personnel**

The Corporation's success depends in large measure on certain key personnel including David Burghardt, Tavis Carlson, Travis Stephenson, Robert Pinckston and Jeff Mazurak. The loss of the services of such key personnel could have an adverse effect on the Corporation. The Corporation does not have key person insurance in effect for management. The contributions of these individuals to the immediate operations of the Corporation are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Readers must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

**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 to be 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, 2015. 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, 2015. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2015 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, 2015, and identifies the respective portions thereof that we have evaluated and reported on to the Company's Management and Board of Directors:

**Altura Energy Inc.**
**Forecast Prices and Costs**

| | | | Net Present Value of Future Net Revenue $M (before income taxes, 10% discount rate) | | | |
|---|---|---|---|---|---|---|
| **Independent Qualified Reserves Evaluator** | **Effective Date of Evaluation Report** | **Location of Reserves** | **Audited** | **Evaluated** | **Reviewed** | **Total** |
| McDaniel & Associates | December 31, 2015 | Canada | - | 20,994.0 | - | 20,994.0 |

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.

6. 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.

7. 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 9, 2016

## 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, 2015 (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)
Tavis Carlson
Vice President, Finance & Chief Financial Officer

(signed)
Darren Gee
Director

(signed)
Brian Lavergne
Director

April 28, 2016