ADVANTAGE
OIL & GAS LTD.

ANNUAL INFORMATION FORM

YEAR ENDED DECEMBER 31, 2016

March 2, 2017

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GLOSSARY OF TERMS

Selected Defined Terms

"**2014 Secondary Offering**" means the secondary offering by Advantage of 21,150,010 common shares of Longview at a price of $4.45 per common share, which closed on February 28, 2014;

"**ABCA**" means the *Business Corporations Act* (Alberta), together with any or all regulations promulgated thereunder, as amended from time to time;

"**AOG**" or "**Advantage**" or the "**Corporation**" means Advantage Oil & Gas Ltd., a corporation amalgamated under the ABCA. All references to "**AOG**" or "**Advantage**" or the "**Corporation**", unless the context otherwise requires, are references to Advantage Oil & Gas Ltd. and its predecessors and subsidiaries;

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

"**Common Shares**" means the common shares of Advantage;

"**Credit Facilities**" has the meaning ascribed thereto under the heading "*General Development of the Business – Three Year History – 2014 – Credit Facilities*";

"**GAAP**" means generally accepted accounting principles for publicly accountable enterprises in Canada which is currently in accordance with IFRS;

"**IFRS**" means International Financial Report Standards as issued by the International Accounting Standards Board;

"**Longview**" means Longview Oil Corp., a corporation incorporated under the ABCA;

"**NYSE**" means the New York Stock Exchange;

"**Offering**" means the bought-deal public offering pursuant to a short form prospectus of the Corporation dated March 1, 2016 of up to 13,512,500 Common Shares (including 1,762,500 Common Shares issuable on the exercise of an over-allotment option granted to the underwriters) for gross proceeds of up to $100,668,125;

"**Shareholders**" means the holders from time to time of one or more Common Shares, as shown on the register of such holders maintained by the Corporation or by the transfer agent of the Common Shares, on behalf of the Corporation;

"**TSX**" means the Toronto Stock Exchange; and

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

Selected Defined Oil and Gas Terms

"**abandonment and reclamation costs**" means all costs associated with the process of restoring a property that has been disturbed by oil and gas activities to a standard imposed by applicable government or regulatory authorities;

"**API**" means the American Petroleum Institute;

"**API gravity**" means the American Petroleum Institute gravity expressed in degrees in relation to liquids, which is a measure of how heavy or light a petroleum liquid is compared to water. If a petroleum liquid's API gravity is greater than 10, it is lighter and floats on water; if less than 10, it is heavier than water and sinks. API gravity is thus a measure of the relative density of a petroleum liquid and the density of water, but it is used to compare the relative densities of petroleum liquids;

"**COGE Handbook**" means the "Canadian Oil and Gas Evaluation Handbook" maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter), as amended from time to time;

"**conventional natural gas**" means natural gas that has been generated elsewhere and has migrated as a result of hydrodynamic forces and is trapped in discrete accumulations by seals that may be formed by localized structural, depositional or erosional geological features;

"**developed non-producing reserves**" are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown;

"**developed producing reserves**" are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainly;

"**developed reserves**" are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing;

"**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, to the extent necessary in developing the reserves;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems;

"**exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to as "prospecting costs") 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 (collectively referred to as "geological and geophysical costs");

(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 defence, 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;

"**forecast prices and costs**" means future prices and costs that are:

(a) generally accepted as being a reasonable outlook of the future; or

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Corporation is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in subparagraph (a);

"**future net revenue**" means a forecast of revenue, estimated using forecast prices and costs, arising from the anticipated development and production of resources, net of the associated royalties, operating costs, development costs, and abandonment and reclamation costs;

"**gross**" means:

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

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

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

"hydrocarbon" means a compound consisting of hydrogen and carbon, which, when naturally occurring, may also contain other elements such as sulphur;

"light crude oil" means crude oil with a relative density greater than 31.1 degrees API gravity;

"medium crude oil" means crude oil with a relative density greater than 22.3 degrees API gravity and less than or equal to 31.1 degrees API gravity;

"**natural gas**" means a naturally occurring mixture of hydrocarbon gases and other gases;

"**natural gas liquids**" means those hydrocarbon components that can be recovered from natural gas as a liquid including, but not limited to, ethane, propane, butanes, pentanes plus, and condensates;

"**net**" means:

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

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

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

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

"**property**" includes: (a) fee ownership or a lease, concession, agreement, permit, licence or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest; (b) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and (c) an agreement with a foreign government or authority under which a reporting issuer participates in the operation of properties or otherwise serves as "producer" of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer). A property does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas;

"**probable reserves**" are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves;

"**proved reserves**" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves;

"**reserves**" are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on: (a) analysis of drilling, geological, geophysical and engineering data; (b) the use of established technology; and (c) specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates;

"**resource play**" refers to drilling programs targeted at regionally distributed crude oil or natural gas accumulations; successful exploitation of these reservoirs is dependent upon technologies such as horizontal drilling and multi-stage fracture stimulation to access large rock volumes in order to produce economic quantities of oil or natural gas;

"**Sproule**" has the meaning ascribed thereto under the heading "*Statement of Reserves Data and Other and Gas Information – Disclosure of Reserves Data*";

"**Sproule Report**" has the meaning ascribed thereto under the heading "*Statement of Reserves Data and Other and Gas Information – Disclosure of Reserves Data*"; and

"**undeveloped reserves**" are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

Words importing the singular number only include the plural, and *vice versa*, and words importing any gender include all genders. All dollar amounts set forth in this annual information form are in Canadian dollars, except where otherwise indicated.

ABBREVIATIONS AND OIL AND GAS ADVISORIES

Crude Oil and Natural Gas Liquids

bbls	barrels
Mbbls	thousand barrels
MMbbls	million barrels
NGLs	natural gas liquids
BOE or boe	means barrel of oil equivalent
MMboe	million barrels of oil equivalent
boe/d	barrels of oil equivalent per day
bbls/d	barrels of oil per day

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
bcf	billion cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
MMcfe/d	million cubic feet equivalent per day
MMbtu	million British Thermal Units

Other

AECO	Alberta Energy Company's natural gas storage facility located at Suffield, Alberta
Mcfe	means thousand cubic feet of natural gas equivalent, using the ratio of 6 Mcf of natural gas being equivalent to one bbl of oil
MMcfe	means million cubic feet of natural gas equivalent
MMcfe/d	means million cubic feet equivalent per day
MM$	means millions of dollars
WTI	means West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for the crude oil standard grade

The term "boe" or barrels of oil equivalent and "Mcfe" or thousand cubic feet equivalent may be misleading, particularly if used in isolation. A boe or Mcfe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent (6 Mcf: 1 bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

This annual information from contains certain oil and gas metrics, including reserve life index, which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included herein to provide readers with additional measures to evaluate the Corporation's performance; however, such measures are not reliable indicators of the future performance of the Corporation and future performance may not compare to the performance in previous periods and therefore such metrics should not be unduly relied upon.

Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

CONVERSION

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

To Convert From	To	Multiply By
Mcf	cubic metres	28.317
cubic metres	cubic feet	35.315
Bbls	cubic metres	0.159
cubic metres	bbls	6.289
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
MMbtu	gigajoules	1.0526

FORWARD-LOOKING STATEMENTS

Certain statements contained in this annual information form constitute forward-looking statements. These statements relate to future events or our future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. We believe the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this annual information form should not be unduly relied upon. These statements speak only as of the date of this annual information form.

In particular, this annual information form contains forward-looking statements pertaining to, but not limited to, the following:

- the performance characteristics of our assets;
- crude oil and natural gas production levels;
- the size of the crude oil and natural gas reserves;
- projections of market prices and costs and supply and demand for crude oil and natural gas;
- expectations with respect to pipeline capacity in northwest Alberta and western Canada generally;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- the Corporation's proposed capital expenditure program for 2017, including the estimated amount of capital expenditures; and the focus of the Corporation's capital expenditures and operations, including the Corporation's drilling and facility expansion plans and its ability to maintain and increase production to the levels disclosed herein;
- drilling and future development plans for the Corporation's assets, including the anticipated timing thereof and estimated production therefrom and capital expenditures related thereto;
- estimated timing of capital expenditures;
- targeted production at Glacier and the anticipated timing of achievement of such targets;
- timing of development of undeveloped reserves;
- future abandonment and reclamation costs;
- the Corporation's hedging activities;
- tax horizons and treatment under governmental regulatory regimes and tax laws;
- terms of the Credit Facilities, including the effect of revisions or changes in reserve estimates and commodity prices on the borrowing base of the Credit Facilities; and
- capital expenditures programs.

Statements relating to "reserves" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward looking statements contained in this annual information form are expressly qualified by this cautionary statement.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this annual information form: risks related to changes in general economic, market and business conditions; continued volatility in market prices for crude oil and natural gas; the impact of significant declines in market prices for crude oil and natural gas; stock market volatility; changes to legislation and regulations and how they are interpreted and enforced; the Corporation's ability to comply with current and future environmental or other laws; actions by governmental or regulatory authorities including increasing taxes, changes in investment or other regulations; changes in tax laws, royalty regimes and incentive programs relating to the crude oil and natural gas industry; the effect of acquisitions; Advantage's success at acquisition, exploitation and development of reserves; unexpected drilling results; failure to achieve production targets on timelines anticipated or at all; the potential for management and reserves evaluators estimates and assumptions to be inaccurate; changes in commodity prices, currency exchange rates, capital expenditures, reserves or reserves estimates and debt service requirements; the occurrence of unexpected events involved in the exploration for, and the operation and development of, crude oil and natural gas properties; hazards such as fire, explosion, blowouts, cratering, and spills, each of which could result in substantial damage to wells, production facilities, other property and the environment or in personal injury; geological, technical, drilling and processing problems and other difficulties in producing petroleum reserves; changes or fluctuations in production levels; individual well productivity; delays in anticipated timing of drilling and completion of wells; delays in timing of completion of the Corporation's plant expansion at Glacier; the failure to extend the Credit Facilities at each annual review; competition from other producers for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; the lack of availability of qualified personnel or management; the lack of available capacity on pipelines; ability to access sufficient capital from internal and external sources; credit risk; the other factors discussed under "*Risk Factors*"; and other factors, many of which are beyond the control of the Corporation. Readers are cautioned that the foregoing list of factors is not exhaustive.

Although the forward-looking statements contained in this annual information form are based upon assumptions which Advantage believes to be reasonable, Advantage cannot assure Shareholders that actual results will be consistent with these forward-looking statements. With respect to forward-looking statements contained in this annual information form, Advantage has made assumptions regarding, but not limited to: that the current commodity price and foreign exchange environment will continue or improve; conditions in general economic and financial markets; current and future commodity prices and royalty regimes; availability of skilled labour; timing and amount of capital expenditures; future exchange rates; availability of pipeline capacity; the impact of increasing competition; conditions in general economic and financial markets; availability of drilling and related equipment; effects of regulation by governmental agencies; royalty rates; future operating costs; that the Corporation will have sufficient cash flow, debt or equity sources or other financial resources required to fund its capital and operating expenditures and requirements as needed; that the Corporation’s conduct and results of operations will be consistent with its expectations; that the Corporation will have the ability to develop the Corporation’s crude oil and natural gas properties in the manner currently contemplated; that current or, where applicable, proposed assumed industry conditions, laws and regulations will continue in effect or as anticipated as described herein; that the estimates of the Corporation’s reserves volumes and the assumptions related thereto (including commodity prices and development costs) are accurate in all material respects; and other matters

Advantage has included the above summary of assumptions and risks related to forward-looking information provided in this annual information form in order to provide Shareholders with a more complete perspective on the Corporation's current and future operations and such information may not be appropriate for other purposes. The Corporation's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits Advantage will derive therefrom.

These forward-looking statements are made as of the date of this annual information form and Advantage disclaims any intent or obligation to update publicly any forward-looking statements, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws.

NON-GAAP MEASURES

The Corporation discloses several financial measures in this annual information form that do not have any meaning prescribed under GAAP. These financial measures include funds from operations and cash netbacks. Funds from operations, as presented, is based on cash provided by operating activities before expenditures on decommissioning liability and changes in non-cash working capital reduced for finance expense excluding accretion. Management of the Corporation believes these adjustments to cash provided by operating activities increase comparability between reporting periods. Cash netbacks are dependent on the determination of funds from operations and include the primary cash sales and expenses on a per Mcfe basis that comprise funds from operations. Management believes that these financial measures are useful supplemental information to analyze operating performance and provide an indication of the results generated by the Corporation’s principal business activities. Investors should be cautioned that these measures should not be construed as an alternative to net income, comprehensive income, and cash provided by operating activities or other measures of financial performance as determined in accordance with GAAP. Advantage’s method of calculating these measures may differ from other companies, and accordingly, they may not be comparable to similar measures used by other companies.

ADVANTAGE OIL & GAS LTD.

General

The Corporation was formed pursuant to the amalgamation of Advantage Oil & Gas Ltd., 1335703 Alberta Ltd., SET Resources Inc. and Sound Exchange Co Ltd. under the ABCA on September 5, 2007. On July 9, 2009 the articles of the Corporation were amended to change the number of issued and outstanding Common Shares to equal the number of trust units of Advantage Energy Income Fund (the "**Trust**") outstanding immediately prior to the plan of arrangement pursuant to Section 193 of the ABCA, which closed on July 9, 2009 and pursuant to which, among other things, the Trust was dissolved and the Corporation became the resulting entity.

The Corporation is a reporting issuer in each of the provinces of Canada and the Common Shares are listed on the TSX and NYSE under the symbol "AAV".

The head office of Advantage is located at Suite 300, 440 – 2nd Avenue S.W., Calgary, Alberta T2P 5E9 and its registered office is located at 2400, 525 – 8th Avenue S.W., Calgary, Alberta T2P 1G1.

Corporate Structure

As at December 31, 2016, the Corporation did not have any material direct or indirect subsidiaries, as the total assets and revenues of the Corporation's subsidiaries, on a combined basis, does not exceed 10% of the consolidated assets and the consolidated revenues, respectively, of the Corporation.

GENERAL DEVELOPMENT OF THE BUSINESS

General

The Corporation is engaged in the business of natural gas exploitation, development, acquisition and production in the Province of Alberta. The Corporation is focused on development and growth of its extensive Montney natural gas play at Glacier, Alberta. See "*Description of our Business and Operations*" below.

From 2012 to 2014, Advantage executed on a number of significant transactions with the objective of positioning the Corporation to successfully deliver on its new long-term development plan. Advantage's transformation included the disposition of non-core assets, simplifying the business to focus on its extensive Glacier Montney natural gas asset, strengthening the balance sheet through utilization of net proceeds from dispositions reducing indebtedness, and realigning the Board, management and staff to achieve the Corporation's development plan.

A detailed description of the historical development of the business of the Corporation for the years ended December 31, 2014, 2015 and 2016 is outlined below. Unless the context otherwise requires, references to "we", "us", "our" or similar terms refer to the Corporation.

Three Year History

2014

Strategic Alternatives Process Conclusion

Advantage announced on February 5, 2013 that it had initiated a review of strategic alternatives and on February 26, 2013, the Corporation formed a special committee of independent directors to oversee the strategic alternatives review process with the assistance of its financial advisors. The financial advisors commenced a broad marketing effort to solicit interest in a sale of the Corporation or other strategic transaction to maximize value for all shareholders. Technical presentations were completed and following the bid date, the Corporation, along with its financial advisors, reviewed the proposals received from those parties who submitted bids. On February 4, 2014, the Corporation announced that its strategic alternatives review process had been completed and did not result in an acceptable proposal. During the process, the Corporation received expressions of interest in respect of a variety of potential transactions; however, none of these proposals were determined to be in the best interests of the Corporation and did not adequately reflect the intrinsic value of the Corporation based upon its assets, operations and prospects for growth.

Three Year Development Plan and Budget

On February 4, 2014, the Corporation announced a three year development plan through to 2017 endorsed by the Board and approval of the Glacier capital and operating budget for the 12 months ending March 31, 2015. The Corporation's development plan targeted doubling production at Glacier to 245 MMcfe/d (40,800 boe/d) in 2017 including the extraction of natural gas liquids. Based on well results and cost performance, Advantage expected this plan to be completed within its existing Credit Facilities with total capital expenditures during each 12 month development period to be between $210 million to $270 million with the drilling of approximately 33 wells per 12 month period. The Board approved the Glacier capital budget targets to increase production to approximately 183 MMcfe/d in the second quarter of 2015 including approximately 900 bbls/d of natural gas liquids from an initial 25 MMcf/d development in the Middle Montney.

Termination of Technical Services Agreement

Concurrently with the purchase by Longview from Advantage of certain oil-weighted assets in 2011, Advantage entered into a Technical Services Agreement (the "**TSA**") with Longview, pursuant to which Advantage provided the necessary personnel and technical services to manage Longview's business and Longview reimbursed Advantage on a monthly basis for its share of administrative charges based on respective levels of production. During the term of the TSA, the officers of Longview provided services to Longview under the TSA but remained as employees of Advantage. On February 4, 2014, the Corporation and Longview announced that the TSA was formally terminated and appropriate staffing and systems were in place to enable both organizations to run independently.

Change in Directors and Management

On February 4, 2014, Mr. Steven Sharpe resigned from the Board. Mr Ron McIntosh was elected Chairman. On March 27, 2014, Mr. Neil Bokenfohr, Vice-President Exploitation was appointed as Senior Vice President. On May 26, 2014, Mr. Grant Fagerheim was appointed as a director of the Corporation.

2014 Secondary Offering of Longview Shares

On February 28, 2014, Longview closed the 2014 Secondary Offering, pursuant to which 21,150,010 common shares of Longview held by Advantage were sold at a price of $4.45 per common share for net proceeds to Advantage of $90.0 million. As a result of the 2014 Secondary Offering, Advantage does not own or control or direct, directly or indirectly, any common shares of Longview. All of the net proceeds from the 2014 Secondary Offering were used to reduce indebtedness under the Credit Facilities.

Sale of Questfire Investments

On March 26, 2014, Advantage entered an agreement with Questfire Energy Corp. ("**Questfire**") to redeem the $32.6 million convertible senior secured debenture issued to Advantage on February 5, 2013 at an aggregate purchase price of $13.6 million. In the second quarter of 2014, Questfire also purchased, pursuant to an issuer bid, all of the 1.5 million Class B shares of Questfire held by Advantage at a purchase price of $2.60 per share for gross proceeds of $3.9 million.

Credit Facilities

On May 29, 2014, Advantage announced that its lenders completed their annual review and the borrowing base under its credit facilities (the "**Credit Facilities**") had been increased from $300 million to $400 million.

2015

2015 Development Plan

On February 17, 2015, Advantage announced that the Board had approved a $110 million reduction in the Corporation's 2015 capital program and a $150 million reduced capital program for the entire 2015 to 2017 development period. The Corporation also announced that despite the $110 million capital reduction, it still expected to achieve 12 months production growth of 36% from 135 MMcfe/d to 183 MMcfe/d in July 2015. As a result of improved capital efficiencies from slick water completed wells with higher initial production rates and lower declines, fewer wells were required to achieve targeted production than were originally scheduled for the 2015 through 2017 period.

On August 6, 2015, Advantage announced that it reached the next level of production growth to 183 MMcfe/d on July 20, 2015 with the expansion of its Glacier gas plant and a large inventory of Montney wells that continued to outperform expectations.

Appointment of Director

On May 27, 2015, Ms. Jill T. Angevine was appointed as a director of the Corporation.

Credit Facilities

On May 7, 2015, Advantage announced that its lenders completed their annual review and the borrowing base under its Credit Facilities had been increased to $450 million.

2016 Development Plan

On December 16, 2015, Advantage announced that, based on the assumption of an average AECO $2.50/Mcf natural gas price for 2016 and Advantage's current hedge positions, its Board of Directors had approved a 2016 capital budget of $120 million. As at December 31, 2015, Advantage's standing well inventory consisted of 37 total standing wells of which 23 were completed and 14 remained uncompleted, which management believed would provide sufficient productive capacity to attain the Corporation's estimated average annual production target for the year ended December 31, 2016 of 190 to 210 MMcfe/d.

2016

Glacier Gas Plant

The Glacier gas plant expansion completed in 2015 increased processing capacity to 250 MMcf/d and provided 70 MMcf/d of additional capacity to meet future growth in 2016 and 2017. The Glacier gas plant is capable of processing varying amounts of dry and liquids rich gas providing discretion to vary the number of producing dry or liquids-rich gas wells in order to optimize investment returns and cash netbacks. Advantage is currently progressing with another significant expansion of the Glacier gas plant to increase processing capacity by 150 MMcf/d to a total of 400 MMcf/d with design and regulatory application work underway. Construction on the Glacier gas plant expansion is expected to begin in the second half of 2017 with completion targeted for the second quarter of 2018.

The Offering

On March 8, 2016, Advantage completed the Offering, pursuant to which 13,427,075 Common Shares were issued at a price of $7.45 per Common Share for gross proceeds of $100,031,709, which included the issuance of 1,677,075 Common Shares pursuant to the partial exercise of the over-allotment option granted to the underwriters.

2017 Capital Budget and Development Plan

On November 28, 2016, Advantage announced that, based on the assumption of an average AECO $2.95/Mcf natural gas price for 2017 and Advantage's current hedge positions, its Board of Directors had approved a 2017 capital budget of $195 to $215 million to increase production to 230 to 240 MMcfe/d. Advantage's average annual production for the year ended December 31, 2016 was 203 MMcfe/d. Advantage also announced the Corporation's 2017 through 2019 development plan, which is targeted to increase annual production to 316 MMcfe/d in 2019, with total capital expenditures over the development plan period estimated at $625 million, including the drilling of 83 Montney wells.

Anticipated Changes in the Business

As at the date hereof and other than as disclosed herein, we do not anticipate that any material change in our business will occur during the balance of the 2017 financial year.

Significant Acquisitions

The Corporation did not complete any acquisitions during the year ended December 31, 2016 for which disclosure is required under Part 8 of National Instrument of 51-102 - *Continuous Disclosure Obligations*.

As part of its ongoing business, the Corporation evaluates potential acquisitions of all types of petroleum and natural gas assets. The Corporation is normally in the process of evaluating various potential acquisitions at any one time which individually or together could be material. As of the date hereof, the Corporation has not reached agreement on the price or terms of any potential material acquisitions. The Corporation cannot predict whether any current or future opportunities will result in one or more acquisitions for the Corporation.

DESCRIPTION OF OUR BUSINESS AND OPERATIONS

General

Advantage is engaged in the business of gas exploitation, development, acquisition and production in the Province of Alberta.

Advantage's exploitation and development program is focused at Glacier, Alberta where it is developing a significant natural gas resource play. As current and future practice, Advantage has established a financial hedging strategy and may manage the risk associated with changes in commodity prices by entering into derivatives. See "*Risk Factors*". Although Advantage has a significant capital development program, it also actively evaluates growth opportunities through crude oil and natural gas asset acquisitions, as well as through corporate acquisitions. Advantage targets acquisitions that support and augment its Montney development and long term strategy. It is currently intended that Advantage will finance any acquisitions and investments through the Credit Facilities, the issuance of additional Common Shares from treasury, the issuance of subordinated convertible debentures, or accessing long term debt instruments to maintain prudent leverage.

Reorganizations

As at the date hereof, except as disclosed herein, there have been no material reorganizations of Advantage and or any of its subsidiaries within the three most recently completed financial years and there are currently no material reorganizations of Advantage proposed for the current financial year. See "*General Development of the Business*".

Bankruptcy and Similar Procedures

There have been no bankruptcy, receivership or similar proceedings against the Corporation or any of its subsidiaries or related entities, or any voluntary bankruptcy, receivership or similar proceeding by the Corporation or any of its subsidiaries or related entities since the inception of the Corporation or during or proposed for the current financial year.

Specialized Skill and Knowledge

Advantage employs individuals with various professional skills in the course of pursuing its business plan. These professional skills include, but are not limited to, geology, geophysics, engineering, financial and business skills, which are widely available in the industry. Drawing on significant experience in the oil and gas business, Advantage 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 Advantage to effectively identify, evaluate and execute on its business plan.

Human Resources

As at December 31, 2016, the Corporation employed 27 full-time employees, 25 of which are located in the head office and 2 of which are located in the field. The Corporation also retained 7 consultants in the head office.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Disclosure of Reserves Data

The reserves data set forth below is based upon an evaluation by Sproule Associates Limited ("**Sproule**") with an effective date of December 31, 2016 contained in a report of Sproule dated February 7, 2017 (the "**Sproule Report**"). The Sproule Report evaluated, as at December 31, 2016, the crude oil, NGLs and conventional natural gas reserves of Advantage. The reserves data summarizes Advantage's crude oil, NGLs and conventional natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs. All of the Corporation's reserves are in Canada and, specifically, in the Province of Alberta. The Sproule 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. Sproule was engaged to provide evaluations of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

The report of management and directors on oil and gas disclosure in Form 51-101F3 and the report on reserves data by Sproule in Form 51-101F2 are attached as Schedules "A" and "B" to this annual information form, respectively, which forms are incorporated herein by reference.

There are numerous uncertainties inherent in estimating quantities of crude oil, NGLs and conventional natural gas reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth herein are estimates only. In general, estimates of economically recoverable crude oil, NGLs and conventional natural gas reserves and the future net cash flows therefrom 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, NGL and conventional 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 reserves will vary from estimates thereof and such variations could be material.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of our crude oil, NGLs and conventional natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, NGLs and conventional natural gas reserves may be greater than or less than the estimates provided herein.

The information relating to the Corporation's consolidated crude oil, NGLs and conventional natural gas reserves contains forward-looking statements relating to future net revenues, forecast capital expenditures, future development plans and costs related thereto, forecast operating costs, anticipated production and abandonment costs. See "*Forward-Looking Statements*", "*Industry Conditions*" and "*Risk Factors – Reserves Estimates*".

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

Summary of Oil and Gas Reserves as at December 31, 2016 – Forecast Prices and Costs

	RESERVES			
	LIGHT CRUDE OIL AND MEDIUM CRUDE OIL		**CONVENTIONAL NATURAL GAS**	
RESERVES CATEGORY	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (MMcf)**	**Net (MMcf)**
PROVED				
Developed Producing	8.4	7.3	358,980	331,875
Developed Non-Producing	-	-	50,736	45,306
Undeveloped	-	-	1,027,433	920,521
TOTAL PROVED	8.4	7.3	1,437,149	1,297,701
PROBABLE	2.7	2.3	618,249	537,270
TOTAL PROVED PLUS PROBABLE	11.1	9.6	2,055,398	1,834,971

	RESERVES			
	NATURAL GAS LIQUIDS		**TOTAL OIL EQUIVALENT**	
RESERVES CATEGORY	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mboe)**	**Net (Mboe)**
PROVED				
Developed Producing	3,645.4	2,830.4	63,483.7	58,150.1
Developed Non-Producing	596.9	464.5	9,052.9	8,015.5
Undeveloped	11,281.4	9,013.7	182,520.3	162,433.8
TOTAL PROVED	15,523.7	12,308.6	255,056.9	228,599.4
PROBABLE	8,005.0	6,036.5	111,049.3	95,583.7
TOTAL PROVED PLUS PROBABLE	23,528.8	18,345.1	366,106.2	324,183.1

Summary of Net Present Values of Future Net Revenue of Oil and Gas Reserves as at December 31, 2016 – Forecast Prices and Costs(1)(2)

	Before Income Tax Discounted at (%/year) (2)					**After Income Taxes Discounted at (%/year)(2)(5)**					**Unit Value Before Income Tax Discounted at 10%/ year(4)**
RESERVES CATEGORY	**0% ($000's)**	**5% ($000's)**	**10% ($000's)**	**15% ($000's)**	**20% ($000's)**	**0% ($000's)**	**5% ($000's)**	**10% ($000's)**	**15% ($000's)**	**20% ($000's)**	**($/boe)**
PROVED											
Developed Producing	1,084,909	873,511	720,793	616,180	541,393	1,084,909	873,511	720,793	616,180	541,393	12.40
Developed Non-Producing	186,551	121,630	90,765	72,810	61,008	157,385	110,810	86,444	70,975	60,187	11.32
Undeveloped	2,587,841	1,229,659	614,694	298,395	120,221	1,880,846	878,232	417,772	178,838	43,422	3.78
TOTAL PROVED	3,859,301	2,224,800	1,426,251	987,386	722,622	3,123,140	1,862,553	1,225,009	865,993	645,002	6.24
PROBABLE	2,384,445	1,257,860	787,492	546,369	404,975	1,741,511	921,758	581,245	407,631	306,193	8.24
TOTAL PROVED PLUS PROBABLE	6,243,745	3,482,659	2,213,743	1,533,754	1,127,597	4,864,651	2,784,311	1,806,254	1,273,624	951,195	6.83

Notes:

(1) Advantage's light crude oil and medium crude oil, conventional natural gas and NGL reserves were evaluated using Sproule's product price forecast effective December 31, 2016 prior to interests, debt service charges and general and administrative expenses. It should not be assumed that the future net revenue estimated by Sproule represents the fair market value of the reserves.

(2) Assumes that development of Glacier will occur, without regard to the likely availability to the Corporation of funding required for that development.

(3) Future net revenue incorporates management's estimates of required abandonment and reclamation costs, including expected timing such costs will be incurred, associated with all wells (including undrilled wells that have been attributed reserves), facilities and infrastructure. No abandonment and reclamation costs have been excluded.

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

(5) Values are calculated by considering existing tax pools for Advantage in the evaluation of Advantage's oil and gas properties, and take into account current federal tax regulations. Values do not represent an estimate of the value at the business entity level, which may be significantly different. For information at the business entity level, please see Advantage's Consolidated Financial Statements and Management's Discussion and Analysis for the year ended December 31, 2016.

Total Future Net Revenue (Undiscounted) as at December 31, 2016 – Forecast Prices and Costs[(1)(2)]

RESERVES CATEGORY	REVENUE ($000's)	ROYALTIES ($000's)	OPERATING COSTS ($000's)	DEVELOP-MENT COSTS ($000's)	ABANDONMENT AND RECLAMATION COSTS[(3)] ($000's)	FUTURE NET REVENUE BEFORE INCOME TAXES ($000's)	FUTURE INCOME TAXES ($000's)	FUTURE NET REVENUE AFTER INCOME TAXES [(4)] ($000's)
Proved Reserves	7,643,207	840,278	1,425,609	1,385,396	132,624	3,859,301	736,160	3,123,140
Proved Plus Probable Reserves	11,366,055	1,393,760	1,994,055	1,594,879	139,614	6,243,745	1,379,094	4,864,651

Notes:

(1) Advantage's light crude oil and medium crude oil, conventional natural gas and NGL reserves were evaluated using Sproule's product price forecast effective December 31, 2016 prior to interests, debt service charges and general and administrative expenses. It should not be assumed that the future net revenue estimated by Sproule represents the fair market value of the reserves.

(2) Assumes that development of Glacier will occur, without regard to the likely availability to the Corporation of funding required for that development.

(3) Future net revenue incorporates management's estimates of required abandonment and reclamation costs, including expected timing such costs will be incurred, associated with all wells (including undrilled wells that have been attributed reserves), facilities and infrastructure. No abandonment and reclamation costs have been excluded.

(4) Values are calculated by considering existing tax pools for Advantage in the evaluation of Advantage's oil and gas properties, and take into account current federal tax regulations. Values do not represent an estimate of the value at the business entity level, which may be significantly different. For information at the business entity level, please see Advantage's Consolidated Financial Statements and Management's Discussion and Analysis for the year ended December 31, 2016.

Future Net Revenue by Product Type as at December 31, 2016 – Forecast Prices and Costs

	Net Present Value of Future Net Revenue (before deducting Future Income Tax Expenses and Discounted at 10%/year) ($000's)	Unit Value (before deducting Future Income Tax Expenses and Discounted at 10%/year) ($/Mcf)[3]
Proved reserves		
Light Crude Oil and Medium Crude Oil[1]		
Natural Gas Liquids		
Conventional Natural Gas[2]	1,426,251	$1.04
Total Proved	1,426,251	$1.04
Proved plus Probable reserves		
Light Crude Oil and Medium Crude Oil[1]		
Natural Gas Liquids		
Conventional Natural Gas[2]	2,213,743	$1.14
Total Proved Plus Probable reserves	2,213,743	$1.14

Notes:

(1) Including solution gas and other by-products.
(2) Including by-products, but excluding solution gas and by-products from oil wells.
(3) Unit values are based on net reserve volumes.

Pricing Assumptions

The following tables set forth the benchmark reference prices, as at December 31, 2016, reflected in the reserves data. These price assumptions were provided to us by our independent reserves evaluator, Sproule, and were Sproule's then current forecasts at the date of the Sproule Report.

Summary of Pricing and Inflation Rate Assumption as at December 31, 2016 – Forecast Prices and Costs

Year	Western Canada Select 20.5º API ($Cdn/bbl)	Canadian Light Sweet Crude Oil 40º API ($Cdn/ bbl)	NATURAL GAS AECO-C Spot ($Cdn/ MMBtu)	NATURAL GAS LIQUIDS Edmonton Pentanes Plus ($Cdn/bbl)	NATURAL GAS LIQUIDS Edmonton Butanes ($Cdn/bbl)	OPERATING COST INFLATION RATE %/Year	CAPITAL COST INFLATION RATE %/Year	EXCHANGE RATE [2] ($US/$Cdn)
2017	53.12	65.58	3.44	67.95	47.60	0.0	0.0	0.780
2018	61.85	74.51	3.27	75.61	55.49	2.0	2.0	0.820
2019	64.94	78.24	3.22	78.82	57.65	2.0	2.0	0.850
2020	66.93	80.64	3.91	80.47	58.80	2.0	2.0	0.850
2021	68.27	82.25	4.00	82.15	59.98	2.0	2.0	0.850
2022	69.64	83.90	4.10	83.86	61.18	2.0	2.0	0.850
2023	71.03	85.58	4.19	85.61	62.40	2.0	2.0	0.850
2024	72.45	87.29	4.29	87.39	63.65	2.0	2.0	0.850
2025	73.90	89.03	4.40	89.21	64.92	2.0	2.0	0.850
2026	75.38	90.81	4.50	91.07	66.22	2.0	2.0	0.850
2027	76.88	92.63	4.61	92.96	67.54	2.0	2.0	0.850
Thereafter						Escalation rate of 2% thereafter		

Notes:

(1) This summary table identifies benchmark reference pricing schedules that might apply to a *reporting issuer*.
(2) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical prices, including hedging, realized by the Corporation for the year ended December 31, 2016, were $2.75/Mcf for conventional natural gas, $53.75/bbl for crude oil, and $42.36/bbl for NGLs.

Reconciliations of Changes in Reserves

The following table sets forth a reconciliation of the Corporation's total gross proved, total gross probable and total gross proved plus probable reserves as at December 31, 2016 against such reserves as at December 31, 2015 based on forecast prices and cost assumptions.

	Light Crude Oil and Medium Crude Oil			Natural Gas Liquids		
FACTORS	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**
December 31, 2015	9.4	2.8	12.2	12,097.4	8,023.8	20,121.2
Extensions	-	-	-	3,166.1	800.1	3,966.2
Improved Recovery	-	-	-	-	-	-
Infill Drilling	-	-	-	-	-	-
Technical Revisions(1)	0.5	-	0.5	846.1	(1,070.6)	(224.5)
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Royalty Changes(2)	-	-	-	(166.2)	272.1	105.9
Economic Factors	(0.1)	(0.1)	(0.2)	(85.8)	(20.3)	(106.1)
Production	(1.4)	-	(1.4)	(333.9)	-	(333.9)
December 31, 2016	8.4	2.7	11.1	15,523.7	8,005.1	23,528.8

	Conventional Natural Gas			Oil Equivalent		
FACTORS	**Proved (MMcf)**	**Probable (MMcf)**	**Proved Plus Probable (MMcf)**	**Proved (MBoe)**	**Probable (MBoe)**	**Proved Plus Probable (MBoe)**
December 31, 2015	1,206,484	624,800	1,831,284	213,187.5	112,159.9	325,347.4
Extensions	142,211	32,473	174,684	26,867.9	6,212.3	33,080.2
Improved Recovery	-	-	-	-	-	-
Infill Drilling	-	-	-	-	-	-
Technical Revisions(1)	190,852	(41,588)	149,264	32,655.3	(8,001.9)	24,653.3
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Royalty Changes(2)	(20,901)	4,972	(15,929)	(3,649.7)	1,100.8	(2,548.9)
Economic Factors	(9,087)	(2,408)	(11,495)	(1,600.4)	(421.7)	(2,022.1)
Production	(72,410)	-	(72,410)	(12,403.6)	-	(12,403.6)
December 31, 2016	1,437,149	618,249	2,055,398	255,056.9	111,049.3	366,106.2

Notes:

(1) Technical revisions accounted for 60% of the total proved reserve additions and 46% of the total proved plus probable reserve additions. Percentage of each category calculated by dividing the technical revisions in the category by the total reserve additions in the same category before production.

(2) Royalty changes reflect the adjustment from the Alberta Royalty Framework (ARF) to the Modernized Royalty Framework (MRF).

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by Sproule 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, undeveloped reserves are planned to be developed over the next ten years. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to 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 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.

The following tables set forth the proved undeveloped reserves and the probable undeveloped reserves, each by product type, first attributed to us in each of the following financial years.

Proved Undeveloped Reserves

	Light Crude Oil and Medium Crude Oil (Mbbl)		**Conventional Natural Gas (MMcf)**		**NGLs (Mbbl)**	
Year	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
2014	-	-	102,447	798,870	376.1	6,487.5
2015	-	-	86,336	876,137	2,060.6	8,694.7
2016	-	-	142,211	1,027,433	3,166.1	11,281.4

Sproule has assigned 182.5 MMboe of gross proved undeveloped reserves in the Sproule Report under forecast prices and costs, together with $1.4 billion of associated undiscounted future capital expenditures. Proved undeveloped capital spending in the first two forecast years of the Sproule Report accounts for $422.9 million, or 31%, of the total forecast. These figures increase to $1.1 billion or 81%, during the first five years of the Sproule Report.

For proved undeveloped reserves Sproule assigns reserves based on a 90% probability that the estimated reserves will be recovered. Advantage's expectation is to develop the reserves in a similar timeframe as forecasted by Sproule, which approximates drilling over the next 10 years.

Probable Undeveloped Reserves

	Light Crude Oil and Medium Crude Oil (Mbbl)		**Conventional Natural Gas (MMcf)**		**NGLs (Mbbl)**	
Year	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
2014	-	-	32,596	489,546	974.0	6,039.3
2015	-	-	60,502	497,612	1,252.5	6,658.5
2016	-	-	32,473	481,140	800.1	6,371.5

Sproule has assigned 86.6 MMboe of gross probable undeveloped reserves in the Sproule Report under forecast prices and costs, together with of $207.2 million of associated undiscounted future capital expenditures. Probable undeveloped capital spending in the first two forecast years of the Sproule Report accounts for $21.9 million, or 11%, of the total forecast. These figures increase to $80.2 million or 39%, during the first five years of the Sproule Report.

For proved plus probable reserves Sproule assigns reserves based on a 50% probability that at least the sum of the estimated proved reserves plus probable reserves will be recovered. Advantage's expectation is to develop the reserves in a similar timeframe as forecasted by Sproule, which approximates drilling over the next 10 years.

Significant Factors or Uncertainties

General

The process of estimating reserves is 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 gas prices and costs change. The reserve estimates contained herein are based on production forecasts, prices and economic conditions. The Corporation's reserves are evaluated by Sproule.

As circumstances change and additional data become available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, commodity prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices, and reservoir performance. Such revisions can be either positive or negative.

Abandonment and Reclamation Costs

Abandonment and reclamation costs are based on management's estimate of costs to abandon, remediate and reclaim all of its surface leases, wells (including undrilled wells that have been attributed reserves), facilities, and pipelines based on its working interest, the current regulatory standards, actual abandonment cost history, estimated timing of such expenditures and excludes salvage values. These costs relate to wells and facilities in properties that may or may not have reserves attributed to them. Abandonment and reclamation costs include the Corporation's existing crude oil and natural gas activities and costs associated with future development activities including all development drilling, and dedicated gathering and processing facility expansions or builds, required to enable production of the forecast development in Sproule's report. All existing and future abandonment and reclamation costs are reflected in Sproule's estimate of future net revenue.

The approximate net cost to abandon and reclaim all wells and facilities, discounted at 10%, totals $14.2 million ($139.6 million undiscounted and inflated at 2.0% per annum), all of which are included in the estimate of future net revenue. Management has estimated the net cost to abandon and reclaim all existing wells and facilities totalling $45.1 million undiscounted and uninflated and Sproule has estimated the cost to abandon and reclaim all future facilities and undrilled wells that have been attributed reserves**.** Undiscounted abandonment and reclamation costs expected to be paid over the next three years aggregate $5.6 million with the majority of the remaining costs expected to be incurred between 2041 to 2066.

Future Development Costs

The following table sets forth development costs deducted in the estimation of the Corporation's future net revenue attributable to the reserve categories noted below.

	Forecast Prices and Costs	
Year	**Proved Reserves ($millions)**	**Proved Plus Probable Reserves ($millions)**
2017	192.8	203.5
2018	231.8	245.0
2019	196.5	212.6
2020	270.5	305.7
2021	229.2	236.0
Total: Undiscounted for all years	1,385.4	1,594.9

To fund Advantage's capital program, including future development costs, the Corporation has many financing alternatives available, including partial retention of funds from operations, bank debt financing, issuance of additional Common Shares, and issuance of convertible debentures and other financial instruments. Advantage evaluates the appropriate financing alternatives closely and has made use of all these options dependent on the given investment situation and the capital markets. The Corporation maintains a capital structure that is intended to maximize the investment return to Shareholders as compared to the cost of financing. Advantage expects to continue using all financing alternatives available to continue pursuing its development strategy. The assorted financing instruments have certain inherent costs which are considered in the economic evaluation of pursuing any development opportunity.

There can be no guarantee that funds will be available or that we will allocate funding to develop all of the reserves attributed in the Sproule Report. Failure to develop those reserves would have a negative impact on future production and cash flow and could result in negative revisions to reserves.

The interest 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 assets uneconomic.

Other Oil and Gas Information

Advantage is a natural gas, pure play, growth-oriented Corporation with a significant position in the Montney resource play at Glacier, Alberta. The Corporation operates 100% of its Glacier assets, which allows the Corporation to control the nature and timing of the capital investments necessary to maximize the potential in developing this asset.

Property Descriptions

The following property descriptions are as of December 31, 2016 unless otherwise noted and reserves quoted are as reported in the Sproule Report.

Glacier/Valhalla/Wembley/Progress, Alberta

The Glacier property lies along the Alberta side of the border with British Columbia between Grande Prairie, Alberta and Dawson Creek, British Columbia. The primary zones of interest are within the Triassic Montney and Doig formation siltstones. The Glacier property consists of 91 net sections of land with Doig/Montney interests. The total thickness of the Lower Doig/Montney is up to 300 metres and lends itself to multiple layers of development which contributes to the significant inventory of undrilled wells within this resource play. Based on current reserves assignments as of December 31, 2016, Glacier has a proved plus probable reserve life index ("**RLI**") of 27 years at a production rate of 221 MMcfe/d, which was the average production rate achieved at Glacier during the fourth quarter of 2016. RLI is calculated by dividing the total volume of proved plus probable reserves of 1,934,649 MMcf as provided in the Sproule Report by the fourth quarter production rate and express in years.

Since the spud of the first horizontal well on July 26, 2008 to the end of December 2016, Advantage has drilled and completed 154 net horizontal wells at the Glacier property in either the Triassic Montney or Doig formation siltstones. In addition, two vertical wells drilled into the underlying Belloy Formation are used for acid gas disposal and two vertical and one horizontal well are used as a service wells that support our water disposal system.

As at March 2, 2017, Glacier production is approximately 235 MMcfe/d or 39,200 boe/d which represents virtually 100% of the Corporation's total production. Advantage's Upper, Middle and Lower Montney wells are continuing to demonstrate strong production performance. Advantage's current standing well inventory as at December 31, 2016 consists of 29 total wells of which 13 are completed and 16 remain uncompleted, which management believes provides Advantage with more than sufficient productive capacity to attain its 2017 annual production target with the wells that are currently completed while leaving the 16 uncompleted wells for 2018 growth.

In 2016, Advantage drilled 13 gross (13 net) horizontal wells at Glacier in the Montney and Lower Doig formations. In total, Advantage has participated in drilling 181 gross (172 net) horizontal wells at the Glacier property.

During 2016, Advantage continued with its program to delineate the Glacier land block vertically by drilling and testing wells in intervals other than the historically drilled Doig and Lower Montney. To date, a total of 30 horizontal wells and 3 vertical recompletions have tested and produced in intervals other than the Lower Doig or Lower Montney. This development has resulted in significant delineation and de-risking of the liquid rich Middle Montney resource potential at Glacier.

Advantage owns and operates a 100% working interest gas plant located at 5-02-76-12W6. The plant has a licenced throughput capacity of 260 MMcf/d of raw gas. A major expansion of the Glacier plant was announced in 2016 to increase the capacity from the current licenced level of 260 MMcf/d to 400 MMcf/d including the expansion of hydrocarbon liquid processing capacity to 6,800 bbls/d. Gas is sold through Advantage's sales pipeline system into the TransCanada Pipelines Limited Alberta system. The operating cost structure of the Glacier field is very favorable with combined field and plant operating costs averaging $0.27/Mcfe in 2016.

In 2016, Advantage acquired 16 additional sections of Doig/Montney land rights in the Glacier, Valhalla and Wembley area proximal to our existing land holdings. Subsequent to year end, Advantage acquired an additional 3.5 net sections of Doig/Montney rights near Glacier and Valhalla. Advantage now holds a total of 157 net sections (100,480 net acres) of either Doig or Montney rights that have potential for both natural gas and liquids. The 157 net sections are split between Glacier (91 sections), Valhalla/Wembley (57 sections) and Progress (9 sections).

Advantage has drilled 3 horizontal wells in Valhalla and will begin development of both Wembley and Progress later in 2017 by drilling at least one horizontal well at each property.

Oil and Gas Wells

The following table sets forth the number and status of wells as at December 31, 2016 in which the Corporation has a working interest.

	Oil Wells				**Natural Gas Wells**			
	Producing		**Non-Producing**		**Producing**		**Non-Producing**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta, Canada	-	-	-	-	160	149	49	46

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.

(3) Non-producing includes wellbores shut-in for economic reasons, wellbores not capable of production and wellbores used for disposal of water.

Properties with no Attributed Reserves

The following table sets out our unproved properties as at December 31, 2016.

	Gross Acres	Net Acres
Alberta, Canada	66,576	57,810

Although there are no expiries for 2017, our practice is to exploit and/or develop programs that may result in extending or eliminating potential expirations. We closely monitor all future land expiries as compared to our development programs with the strategy of minimizing undeveloped land expirations relating to significant identified opportunities. Development of the Corporation's properties with no attributed reserves are subject to current industry conditions and uncertainties as indicated under "*Risk Factors*" herein.

Forward Contracts

Our financial results and condition will be dependent on the prices received for natural gas production. Natural gas prices have fluctuated widely and are determined by supply and demand factors, including weather, and general economic conditions in natural gas consuming and producing regions throughout North America. Any upward or downward movement in crude oil, NGL and natural gas prices could have an effect on our financial condition and capital development.

Advantage has an approved hedging policy that utilizes, amongst others, costless collars, options and fixed price swaps to hedge up to 75% of its gross crude oil, NGLs and natural gas production for a maximum period of three years and 50% over the fourth year. These hedging activities could expose the Corporation to losses or gains. To the extent that the Corporation engages in risk management activities related to commodity prices, it will be subject to credit risk associated with the parties with which it contracts. This credit risk will be mitigated by entering into contracts with only stable and creditworthy parties and through the frequent review of the Corporation's exposure to these entities. See "*Risk Factors*".

Advantage has the following derivatives in place:

Description of Derivative	Term	Volume	Price
Natural gas – AECO			
Fixed price swap	January 2016 to March 2017	2,370 mcf/d	Cdn $3.98/mcf
Fixed price swap	January 2016 to March 2017	16,587 mcf/d	Cdn $3.97/mcf
Fixed price swap	January 2016 to March 2017	4,739 mcf/d	Cdn $3.75/mcf
Fixed price swap	January 2016 to March 2017	9,478 mcf/d	Cdn $3.76/mcf
Fixed price swap	April 2016 to March 2017	14,217 mcf/d	Cdn $4.11/mcf
Fixed price swap	April 2016 to March 2017	14,217 mcf/d	Cdn $3.25/mcf
Fixed price swap	April 2016 to March 2017	18,956 mcf/d	Cdn $3.22/mcf
Fixed price swap	January 2017 to June 2017	14,217 mcf/d	Cdn $3.00/mcf
Fixed price swap	April 2017 to June 2017	28,434 mcf/d	Cdn $3.00/mcf
Fixed price swap	April 2017 to March 2018	4,739 mcf/d	Cdn $3.27/mcf
Fixed price swap	April 2017 to March 2018	14,217 mcf/d	Cdn $3.27/mcf
Fixed price swap	November 2017 to March 2018	18,956 mcf/d	Cdn $3.22/mcf
Fixed price swap	July 2017 to March 2018	4,739 mcf/d	Cdn $3.02/mcf
Fixed price swap	July 2017 to March 2018	14,217 mcf/d	Cdn $3.01/mcf
Fixed price swap	July 2017 to March 2018	14,217 mcf/d	Cdn $3.00/mcf
Fixed price swap	July 2017 to June 2018	14,217 mcf/d	Cdn $3.00/mcf
Fixed price swap	April 2017 to March 2018	23,695 mcf/d	Cdn $3.01/mcf
Call option sold	April 2017 to December 2018	23,695 mcf/d	Cdn $3.17/mcf (1)
Fixed price swap	October 2017 to September 2018	4,739 mcf/d	Cdn $3.01/mcf
Call option sold	October 2017 to December 2018	4,739 mcf/d	Cdn $3.01/mcf (2)
Fixed price swap	October 2017 to September 2018	4,739 mcf/d	Cdn $3.01/mcf

Description of Derivative	Term	Volume	Price
Call option sold	October 2017 to December 2018	4,739 mcf/d	Cdn $3.06/mcf (3)
Fixed price swap	October 2017 to September 2018	4,739 mcf/d	Cdn $3.01/mcf
Call option sold	October 2017 to December 2018	4,739 mcf/d	Cdn $3.11/mcf (4)
Fixed price swap	October 2018 to March 2019	18,956 mcf/d	Cdn $3.00/mcf
Fixed price swap	October 2018 to March 2019	18,956 mcf/d	Cdn $3.00/mcf
Fixed price swap	October 2018 to March 2019	9,478 mcf/d	Cdn $3.00/mcf
Natural gas – AECO/Henry Hub Basis Differential			
Basis swap	January 2018 to December 2019	25,000 mcf/d	Henry Hub less US $0.85/mcf

Notes:

(1) Call option sold is only exercisable by the counterparty if AECO exceeds Cdn $3.43/mcf.
(2) Call option sold is only exercisable by the counterparty if AECO exceeds Cdn $3.32/mcf.
(3) Call option sold is only exercisable by the counterparty if AECO exceeds Cdn $3.38/mcf.
(4) Call option sold is only exercisable by the counterparty if AECO exceeds Cdn $3.43/mcf.

Tax Horizon

In 2016, we did not pay any income related taxes and it is expected, based on current legislation that no cash income taxes are to be paid by Advantage prior to 2021. See "*Risk Factors*".

Capital Expenditures

The following tables summarize capital expenditures (including capitalized general and administrative expenses) related to our activities for the year ended December 31, 2016:

Capital Expenditures ($ thousands)	2016
Drilling, completions and workovers	56,189
Well equipping and facilities	65,657
Other	167
Expenditures on property, plant and equipment	122,013
Property Acquisition – Proved Properties	-
Property Acquisition – Unproved Properties	6,001
Property dispositions	-
Exploration costs	-
Development costs	-
Total capital expenditures	128,014

Exploration and Development Activities

The following table sets forth the gross and net wells in which we participated during the year ended December 31, 2016:

	Exploratory		Development		Total	
	Gross	Net	Gross	Net	Gross	Net
Oil wells	-	-	-	-	-	-
Gas wells	-	-	13	13	13	13
Service wells	-	-	-	-	-	-
Stratigraphic test wells	-	-	-	-	-	-
Dry holes	-	-	-	-	-	-
Total	-	-	13	13	13	13

Subject to, among other things, the availability of drilling rigs and weather that permits access to drill sites, in the first 6 months of 2017, we plan to drill 10 net wells and complete 11 net wells. See "*Other Oil and Gas Information – Property Descriptions*" for a description of the Corporation's exploration and development activities.

Production Estimates

The following table sets out the volume of our production estimated for the year ended December 31, 2017 reflected in the estimate of future net revenue disclosed in the tables contained under "*Disclosure of Reserves Data*".

	Light Crude Oil and Medium Crude Oil (bbls/d)		Conventional Natural Gas (Mcf/d)		Natural Gas Liquids (bbls/d)		Total (Boe/d)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved Producing	2	2	169,576	157,589	1,733	1,577	29,998	27,843
Proved Developed Non-Producing	-	-	8,216	7,619	50	46	1,420	1,316
Proved Undeveloped	-	-	29,663	28,181	182	173	5,126	4,870
Total Proved	2	2	207,455	193,389	1,966	1,796	36,544	34,030
Total Probable	-	-	21,130	19,830	177	165	3,699	3,470
Total Proved Plus Probable	2	2	228,585	213,219	2,144	1,962	40,243	37,500

The following table indicates our production estimated from our important fields for the year ended December 31, 2017:

	Light Crude Oil and Medium Crude Oil (bbls/d)	Conventional Natural Gas (Mcf/d)	Natural Gas Liquids (bbls/d)	Total (Boe/d)
Alberta – Glacier Property	-	225,352	2,000	39,559

Production History

The following tables summarize certain information in respect of production, prices received, royalties paid, production costs, transportation costs and resulting netback for the periods indicated below:

	Quarter Ended 2016 Mar. 31	June 30	Sept. 30	Dec. 31	Year Ended Dec. 31, 2016
Average Daily Production[(1)]					
Light Crude Oil and Medium Crude Oil (bbls/d)	280	581	524	418	451
NGLs (bbls/d)	138	502	681	531	464
Conventional Natural Gas (Mcf/d)	164,618	203,791	207,332	215,369	197,852
Combined (Mcfe/d)	167,126	210,289	214,562	221,063	203,342
Average Prices Received[(3)]					
Light Crude Oil and Medium Crude Oil ($/bbl)	32.61	57.98	52.36	63.72	53.75
NGLs ($/bbl)	28.36	46.53	40.36	44.59	42.36
Conventional Natural Gas ($/Mcf)	1.72	1.10	2.08	3.02	2.01
Combined ($/Mcfe)	1.77	1.34	2.27	3.17	2.18
Royalties Paid					
Light Crude Oil and Medium Crude Oil ($/bbl)	0.04	0.04	0.02	0.06	0.04
NGLs ($/bbl)	5.16	5.50	4.87	7.77	5.90
Conventional Natural Gas ($/Mcf)	0.07	(0.09)	0.07	0.16	0.05
Combined ($/Mcfe)	0.07	(0.08)	0.08	0.18	0.07
Production Costs [(4)] [(5)]					
Light Crude Oil and Medium Crude Oil ($/bbl)	0.60	0.60	0.66	0.78	0.66

	Quarter Ended 2016 Mar. 31	June 30	Sept. 30	Dec. 31	Year Ended Dec. 31, 2016
NGLs ($/bbl)	0.30	0.06	0.06	0.06	0.06
Conventional Natural Gas ($/Mcf)	0.35	0.30	0.26	0.22	0.28
Combined ($/Mcfe)	0.35	0.30	0.25	0.22	0.27
Transportation Costs					
Light Crude Oil and Medium Crude Oil ($/bbl)	-	-	-	-	-
NGLs ($/bbl)	15.74	11.76	16.37	20.58	16.29
Conventional Natural Gas ($/Mcf)	-	-	-	0.21	0.06
Combined ($/Mcfe)	0.01	0.03	0.05	0.26	0.09
Netback Received(2) (6)					
Light Crude Oil and Medium Crude Oil ($/bbl)	31.97	57.34	51.68	62.88	53.05
NGLs ($/bbl)	7.16	29.21	19.06	16.18	20.11
Conventional Natural Gas ($/Mcf)	1.30	0.89	1.75	2.43	1.62
Combined ($/Mcfe)	1.34	1.09	1.89	2.51	1.75

Notes:

(1) Before deduction of royalties.
(2) Netbacks are calculated by subtracting royalties, production costs and transportation costs from revenues.
(3) Before (gain) loss on Risk Management Contracts.
(4) This figure includes all field operating expenses.
(5) We do not record operating expenses on a commodity basis. Information in respect of operating expenses for crude oil and NGLs ($/bbl) and natural gas ($/Mcf) has been determined by allocating expenses on a relative volume of crude oil, NGLs and natural gas production basis.
(6) Information in respect of netbacks received for crude oil and NGLs ($/bbl) and natural gas ($/Mcf) is calculated using operating expense figures for crude oil and NGLs ($/bbl) and natural gas ($/Mcf), which figures have been estimated. See note (5) above.

The following table indicates our approximate average daily production from our important fields for the year ended December 31, 2016:

	Light Crude Oil and Medium Crude Oil (bbls/d)	Conventional Natural Gas (Mcf/d)	Natural Gas Liquids (bbls/d)	Total (Mcfe/d)
Alberta – Glacier Property	-	197,265	896	202,584

Marketing

Our natural gas and NGL production is primarily sold through marketing companies at current market prices. Commodity risk management is done outside of our marketing contracts. Natural gas contracts are for one year and are cancellable on 30 days notice. None of our natural gas production is sold to aggregators who accumulate production from various producers and market the gas on behalf of the group. NGL contracts are typically renegotiated annually and run for one year and are cancellable on 30 days notice.

Cyclical and Seasonal Impact of Industry

Our operational results and financial condition will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect on our financial condition. We mitigate such price risk through closely monitoring the various commodity markets and establishing hedging programs, as deemed necessary, to fix netbacks on production volumes. See "*Other Oil and Gas Information – Forward Contracts*" for our current hedging program.

Environmental Considerations

We are pro-active in our approach to environmental concerns. Procedures are in place to ensure that significant care is taken in the day-to-day management of our oil and gas properties. Government regulations and procedures are followed in strict adherence to the law. We believe in well abandonment and site restoration in a timely manner to ensure minimal damage to the environment and lower overall costs to us. Our Environmental Management System is continuously updated and meets or exceeds the Canadian Association of Petroleum Producers ("**CAPP**") Environmental Management Guidelines.

Health, Safety and Environmental

Advantage is committed to a comprehensive and effective health, safety and environmental program that meets or exceeds regulatory and corporate requirements.

Advantage participates in the Certificate of Recognition ("**COR**") Safety Program and has received certification for the last six years. The COR Health and Safety Auditing and the COR Safety Program requires commitment to continuous improvement in the environment, health and safety management practices including sound planning and implementation. The program is audited externally every 3 years and internally every other year. The program ensures open communication and measured performance to maintain such program.

Management, employees and all contractors are responsible and accountable for the overall health, safety and environmental program. Advantage will operate in compliance with all applicable regulations and will ensure all staff and contractors employ sound practices to protect the environment and to ensure employee and public health and safety.

In 2016, the Corporation met the AER Enhanced Production Audit Program with a compliance rating for Glacier of 100% satisfactory, which exceeds the industry average by 25%, and Advantage's incident ratings in 2016 were significantly below industry averages. In addition, a total of 36 reclamation certificates were received by Advantage in 2016. Advantage's spill volumes in 2016 were zero and in the last three years were negligible.

The Corporation maintains and will maintain a safe and environmentally responsible work place and provide training, equipment and procedures to all individuals in adhering to our policies. The Corporation will also solicit and take into consideration input from our neighbours, communities and other stakeholders in regard to protecting people and the environment.

Competitive Conditions

There is considerable competition in the worldwide oil and natural gas industry, including the Province of Alberta where the Corporation's assets, activities, and employees are located. We are a member of the petroleum industry, which is highly competitive at all levels. We compete with other companies for all of our business inputs, including exploitation and development prospects, access to commodity markets, acquisition opportunities, available capital and staffing. We strive to be competitive by maintaining a strong financial condition and by utilizing current technologies to enhance exploitation, development and operational activities. See "*Risk Factors*".

DIRECTORS AND OFFICERS

The following table sets forth the name, place of residence, date first elected as a director of Advantage and positions for each of the directors and officers of Advantage as at the date hereof, together with their principal occupations during the last five years.

Name, Province and Country of Residence	Position Held and Period Served as a Director or Officer[(4)(5)]	Principal Occupations During Past Five Years
Andy J. Mah Alberta, Canada	President since April 21, 2011, Chief Executive Officer since January 27, 2009 and a Director since June 23, 2006	President since April 21, 2011. Chief Executive Officer since January 27, 2009. President and Chief Operating Officer from June 23, 2006 to January 27, 2009. Chief Operating Officer of Longview from December 15, 2010 to November 7, 2013. Prior thereto, President of Ketch Resources Ltd. from October 2005 to June 2006. Chief Operating Officer of Ketch Resources Ltd. from January 2005 to September 2005. Prior thereto, Executive Officer and Vice President, Engineering and Operations of Northrock Resources Ltd. from August 1998 to January 2005.
Ronald A. McIntosh[(2)(3)] Alberta, Canada	Director since September 25, 1998[(6)] Chairman since February 4, 2014	Chairman of North American Energy Partners Inc., a publicly traded corporation and a director of Fortaleza Energy Inc., previously known as Alvopetro Inc., formerly named Fortress Energy Inc. Mr. McIntosh has extensive experience in the energy business. His previous roles included President and Chief Executive Officer of Navigo Energy, Chief Operating Officer of Gulf Canada, Vice President Exploration and International of PetroCanada and Chief Operating Officer of Amerada Hess Canada.
Stephen E. Balog[(1)(2)(3)] Alberta, Canada	Director since August 16, 2007	President, West Butte Management Inc., a private consulting company that provides technical and business advisory services to oil and gas operators. Formerly Principal of Alconsult International Ltd., and prior thereto President, Chief Operating Officer and a Director of Tasman Exploration Ltd. from 2001 to June, 2007. Mr. Balog has extensive oil and gas industry experience in the management and operation of senior and junior production companies. He was a key contributor to the development and use of the Canadian Oil & Gas Evaluation Handbook as an industry standard for reserves evaluation, and has previously served on the Petroleum Advisory Committee, Alberta Securities Commission.
Grant Fagerheim[(2)(3)] Alberta, Canada	Director since May 26, 2014	Chairman, President and Chief Executive Officer of Whitecap Resources Inc., a public oil and gas company, since June, 2008. Prior thereto, Mr. Fagerheim was the President and Chief Executive Officer and a Director of Cadence Energy Inc. (formerly, Kereco Energy Ltd.), a public oil and gas company, from January 2005 to September 2008. Mr. Fagerheim received his Bachelor's degree in Education (Economics Minor) from the University of Calgary in 1983 and attended the Executive MBA at Queen's University in 1995. Mr. Fagerheim currently sits on the board of directors of PRD Energy Inc., a public oil and gas company.
Paul Haggis[(1)(2)(3)] Alberta, Canada	Director since November 7, 2008	Mr. Haggis' was President and Chief Executive Officer of Ontario Municipal Employees Retirement System (OMERS) from September 2003 to March 2007, Interim Chief Executive Officer of the Public Sector Pension Investment Board (PSPIB) during 2003 and Executive Vice-President, Development and Chief Credit Officer of Manulife Financial in 2002. Mr. Haggis has extensive financial markets and public board experience having served on the Board of Directors of Canadian Tire Bank until March 30, 2012. He was a director and Chair of the Investment Committee of the Insurance Corporation of British Columbia and currently serves as an advisor to the committee. He was also Chair of the Audit Committee of C.A. Bancorp and Prime Restaurants Royalty Income Fund and the Chair of Canadian Pacific Railway. Currently he is on the Board of Pure Industrial Real Estate Trust, a director of Sunshine Village Corp, a private Alberta company and is Chairman of Alberta Enterprise Corp. Mr. Haggis holds a Bachelor of Arts degree from the University of Western Ontario and is certified as a Chartered Director through the Directors College at McMaster University.
Jill T. Angevine[(1)(2)] Alberta, Canada	Director since May 27, 2015	Vice President and Portfolio Manager at Matco Financial Inc. (an independent, privately held asset management firm) since October 2013. Independent businesswoman from September 2011 until October 2013 and prior thereto, Vice President and Director, Institutional Research at FirstEnergy Capital Corp. (a financial advisory and investment services provider in the energy market).

Name, Province and Country of Residence	Position Held and Period Served as a Director or Officer(4)(5)	Principal Occupations During Past Five Years
Craig Blackwood Alberta, Canada	Vice President, Finance since January 27, 2009 and Chief Financial Officer since August 1, 2013	Chief Financial Officer of Advantage since August 1, 2013. Vice President, Finance of Advantage since January 27, 2009. Chief Financial Officer of Longview from March 4, 2010 to February 4, 2014. Mr. Blackwood is a Chartered Accountant and was the Director of Finance of Advantage from November 2004 to January 27, 2009.
Neil Bokenfohr Alberta, Canada	Senior Vice President, since March 27, 2014	Senior Vice President since March 27, 2014. Vice-President, Exploitation of Advantage from June 23, 2006 to March 27, 2014. Vice-President, Exploitation of Longview from May 13, 2011 to November 7, 2013. Prior thereto, Vice President Exploitation and Operations of Ketch Resources Ltd. from January 2005 to June 2006; Vice President, Engineering of Bear Creek Energy Ltd. (and Crossfield Gas Corp. prior thereto) from March 2002 to January 2005. Prior thereto, Director of Exploitation for Calpine Canada Natural Gas Company from December 2000 to March 2002.
Jay P. Reid Alberta, Canada	Corporate Secretary, Since April, 2001	Partner at the Calgary based law firm of Burnet, Duckworth & Palmer LLP and has practiced corporate and securities law since 1990. He has served, and continues to serve, as a director or officer of a number of private and publicly listed issuers.

Notes:

(1) Member of the Audit Committee.
(2) Member of the Human Resources, Compensation and Corporate Governance Committee.
(3) Member of the Independent Reserve Evaluation Committee.
(4) Advantage does not have an executive committee of the Board.
(5) Advantage's directors shall hold office until the next annual general meeting of Shareholders or until each director's successor is appointed or elected pursuant to the ABCA.
(6) The period of time served by Ronald A. McIntosh as a director of Advantage includes the period of time served as a director of Search prior to the Amalgamation, where applicable. Mr. McIntosh was appointed a director of post-Reorganization Search on May 24, 2001.

As at March 2, 2017, the directors and executive officers of Advantage, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 2,264,509 Common Shares, or approximately 1.2% of the issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Other than as disclosed below:

(a) no director or executive officer of Advantage has, within the last ten years prior to the date of this annual information form, been a director, chief executive officer or chief financial officer of any issuer (including Advantage) that, (i) while the person was acting in the capacity as director, chief executive officer or chief financial officer, was the subject of a cease trade or similar order or an order that denied the company access to any exemption under securities legislation, that was in effect for a period of more than thirty (30) consecutive days; or (ii) was subject to an order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer of an issuer, in the issuer being the subject of a cease trade or similar order or an order that denied the relevant issuer access to any exemption under securities legislation, for a period of more than thirty (30) consecutive days, which resulted from an event that occurred while that person was acting as a director, chief executive officer or chief financial officer of the issuer;

(b) no director or executive officer of Advantage or security holder holding a sufficient number of securities of Advantage to affect materially the control of Advantage is, as at the date of this annual information form, or has, within the last ten years prior to the date of this annual information form, been a director or executive officer of any company (including Advantage) that, while such 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 for compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets;

(c) no director or executive officer of Advantage or securityholder holding a sufficient number of securities of Advantage to affect materially the control of Advantage has, within the last ten years prior to the date of this document, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become 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, officer or securityholder; and

(d) no director or executive officer of Advantage or securityholder holding a sufficient number of securities of Advantage to affect materially the control of Advantage has been subject to: (i) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (ii) 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.

Mr. McIntosh is a director of Fortaleza Energy Inc. ("**Fortaleza**"). On March 2, 2011, the Court of Queen's Bench of Alberta granted an order (the "**Order**") under the *Companies' Creditors Arrangement Act* (Canada) ("**CCAA**") staying all claims and actions against Fortaleza and its assets and allowing Fortaleza to prepare a plan of arrangement for its creditors if necessary. Fortaleza took such step in order to enable Fortaleza to challenge a reassessment issued by the Canada Revenue Agency ("**CRA**"). As a result of the reassessment, if Fortaleza had not taken any action, it would have been compelled to immediately remit one half of the reassessment to the CRA and Fortaleza did not have the necessary liquid funds to remit, although Fortaleza had assets in excess of its liabilities with sufficient liquid assets to pay all other liabilities and trade payables. Fortaleza believed that the CRA's position was not sustainable and vigorously disputed the CRA's claim. Fortaleza filed a Notice of Objection to the reassessment and on October 20, 2011 announced that its Notice of Objection was successful, CRA having confirmed there were no taxes payable. As the CRA claim had been vacated and no taxes or penalties were owing Fortaleza no longer required the protection of the Order under the CCAA and on October 28, 2011 the Order was removed. On March 3, 2011 the TSX suspended trading in the securities of Fortaleza due to Fortaleza having been granted a stay under the CCAA. In addition the securities regulatory authorities in Alberta, Ontario and Quebec issued a cease trade order with respect to Fortaleza for failure to file its annual financial statements for the year ended December 31, 2010 by March 31, 2011. The delay in filing was due to Fortaleza being granted the CCAA order on March 2, 2011 and the resulting additional time required by its auditors to deliver their audit opinion. The required financial statements and other continuous disclosure documents were filed on April 29, 2011 and the cease trade order was subsequently removed. On September 1, 2010 Fortaleza closed the sale of substantially all of its oil and gas assets. As a result of the sale Fortaleza was delisted from the TSX on March 30, 2011 as it no longer met minimum listing requirements.

Mr. Fagerheim was formerly a director of The Resort at Copper Point Ltd. (a private real estate development company) which was placed in voluntary receivership in February 2009.

Conflicts of Interest

The directors and officers of Advantage may, from time to time, be involved in the business and operations of other issuers, in which case a conflict may arise. The ABCA provides that in the event a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided under the ABCA. To the extent that conflicts of interests arise, such conflicts will be resolved in accordance with the provisions of the ABCA.

As at March 2, 2017, other than as disclosed herein, the Corporation was not aware of any existing or potential material conflicts of interest between the Corporation and a director or officer of the Corporation.

DIVIDEND POLICY

The Corporation did not pay any dividends during the years ended December 31, 2016, 2015 and 2014 and does not anticipate paying dividends in the immediate future and will instead direct cash flow to capital expenditures and debt reduction. The amount of future cash dividends, if any, is not assured and will be subject to the discretion of the Board of Directors and may vary depending on a variety of factors, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates, contractual restrictions (including under the Credit Facilities), financing agreement covenants, solvency tests imposed by corporate law and other factors that the Board of Directors may deem relevant. See "*Risk Factors*".

DESCRIPTION OF THE CORPORATION'S SECURITIES

Share Capital

The Corporation is authorized to issue an unlimited number of Common Shares, non-voting shares, preferred shares and exchangeable shares. As of December 31, 2016, there were 184,654,333 Common Shares issued and outstanding and there were no non-voting shares, preferred shares or exchangeable shares issued and outstanding.

The following is a description of the rights attaching to the Common Shares, non-voting shares and the preferred shares.

Common Shares

Each Common Share entitles its holder to receive notice of and to attend all meetings of the shareholders of Advantage and to one vote at such meetings. The holders of Common Shares are, at the discretion of the Advantage Board of Directors and subject to applicable legal restrictions, entitled to receive any dividends declared by the Board of Directors on the Common Shares. The holders of Common Shares are entitled to share equally in any distribution of the assets of Advantage upon the liquidation, dissolution, bankruptcy or winding-up of Advantage or other distribution of its assets among its shareholders for the purpose of winding-up its affairs. Such participation is subject to the rights, privileges, restrictions and conditions attaching to any instruments having priority over the Common Shares.

Non-Voting Shares

The non-voting shares have identical rights to the Common Shares except that holders of non-voting shares are not generally entitled to receive notice of or attend at meetings of shareholders of Advantage or to vote their shares at such meetings.

Preferred Shares

The preferred shares may be issued, from time to time, in one or more series, each series consisting of such number of preferred shares as determined by the Board of Directors, who may also fix the designations, rights, privileges, restrictions and conditions attached to the shares of each series of preferred shares. No preferred shares are presently issued and outstanding. The preferred shares of each series shall, with respect to payment of dividends and distributions of assets in the event of liquidation, dissolution or winding-up of Advantage, whether voluntary or involuntary, or any other distribution of the assets of Advantage among its shareholders for the purpose of winding-up its affairs, rank on a parity with the preferred shares of every other series and shall be entitled to preference over the Common Shares and the shares of any other class ranking junior to the preferred shares.

PRICE RANGE AND TRADING VOLUME OF SECURITIES

Common Shares

The Common Shares are listed and trade on the TSX and the NYSE and commenced trading under the symbol "AAV" on July 9, 2009. The following table sets forth the trading history of the Common Shares for the periods indicated.

Period	High	Low	Volume
	($)	($)	
TSX Trading			
<u>2016</u>			
January	7.87	6.10	14,054,317
February	8.13	6.61	17,503,025
March	7.56	6.44	20,344,342
April	7.23	6.41	30,099,338
May	7.78	6.59	13,561,532

Period	High	Low	Volume
	($)	($)	
June	7.99	6.80	15,093,750
July	8.66	6.96	18,600,398
August	9.50	8.01	11,557,320
September	9.57	8.58	10,448,280
October	10.33	8.94	17,490,848
November	10.10	8.57	12,542,770
December	10.04	8.92	9,583,254
2017			
January	9.31	8.22	12,769,130
February	8.83	7.86	10,056,301
March 1	8.18	8.01	459.658
NYSE Trading (U.S.$)			
2016			
January	5.625	4.165	3,426,048
February	5.85	4.89	2,908,048
March	5.738	4.817	2,600,971
April	5.75	4.97	1,523,445
May	6.03	5.10	1,450,781
June	6.31	5.25	1,947,456
July	6.59	5.38	2,040,740
August	7.43	6.11	2,507,420
September	7.40	6.50	1,583,341
October	7.877	6.70	2,609,414
November	7.55	6.40	2,342,133
December	7.55	6.65	2,343,212
2017			
January	6.90	6.20	2,210,186
February	6.70	6.00	1,817,630
March 1	6.10	5.90	144,982

Prior Sales

During the year ended December 31, 2016, the Corporation did not grant any stock options pursuant to the Corporation's stock option plan and granted 661,571 performance awards pursuant to the Corporation's restricted and performance award incentive plan.

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTIONS ON TRANSFER

There are presently no Advantage securities held in escrow or subject to contractual restrictions on transfer.

LEGAL PROCEEDINGS

There are no outstanding legal proceedings and Advantage and its subsidiaries were not involved in any legal proceedings during the year ended December 31, 2016, which involved claims in excess of 10% of the Corporation's current asset value and to which Advantage or its subsidiaries were a party or in respect of which any of its properties are subject, nor are there any such proceedings known to be contemplated.

REGULATORY ACTIONS

During the year ended December 31, 2016 there were: (i) no penalties or sanctions imposed against Advantage or its subsidiaries by a court relating to securities legislation or by a securities regulatory authority; (ii) no other penalties or sanctions imposed by a court or regulatory body against Advantage or its subsidiaries that would likely be considered important to a reasonable investor in making an investment decision; and (iii) no settlement agreements Advantage or its subsidiaries entered into before a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors and executive officers of Advantage or its subsidiaries or nominees for director of Advantage or its subsidiaries, any Shareholder who beneficially owns or directs or controls more than 10% of the Common Shares or any known associate or affiliate of such persons in any transaction during the year ended December 31, 2016 or in any proposed transaction which has materially affected or would materially affect Advantage or its subsidiaries.

MATERIAL CONTRACTS

Except for contracts entered into by us in the ordinary course of business or otherwise disclosed herein, the only agreement which is material to Advantage is the Credit Facility, a copy of which is available at www.sedar.com. See "*General Development of the Business – Three Year History*".

INTEREST 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 *Continuous Disclosure Obligations* by us during, or related to, our most recently completed financial year other than Sproule Associates Limited, our independent engineering evaluator, and PricewaterhouseCoopers LLP, our current auditors. As at the date hereof, none of the principals of Sproule Associates Limited had any registered or beneficial interests, direct or indirect, in any securities or other property of Advantage or of our 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. PricewaterhouseCoopers LLP have confirmed that they are independent in accordance with the relevant rules and related interpretation prescribed by the Chartered Professional Accountants of Alberta and the rules of the SEC and the relevant legislation and requirements of the Public Company Accounting Oversight Board (PCAOB).

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of Advantage or of any associate or affiliate of Advantage.

AUDITORS, TRANSFER AGENT AND REGISTRAR

Our auditors are PricewaterhouseCoopers LLP, Calgary, Alberta.

Computershare Trust Company of Canada at its offices in Calgary, Alberta and Toronto, Ontario acts as the transfer agent and registrar for the Common Shares.

AUDIT COMMITTEE INFORMATION

Composition of the Audit Committee

The Corporation's audit committee (the "**Audit Committee**") is comprised of Messrs. Paul Haggis and Stephen Balog and Ms. Jill T. Angevine. The following chart sets out the assessment of each Audit Committee member's independence, financial literacy and relevant educational background and experience supporting such financial literacy.

Name, Province and Country of Residence	Independent	Financially Literate	Relevant Education and Experience
Paul Haggis Alberta, Canada	Yes	Yes	Mr. Haggis' was President and Chief Executive Officer of Ontario Municipal Employees Retirement System (OMERS) from September 2003 to March 2007, Interim Chief Executive Officer of the Public Sector Pension Investment Board (PSPIB) during 2003 and Executive Vice-President, Development and Chief Credit Officer of Manulife Financial in 2002. Mr.

Name, Province and Country of Residence	Independent	Financially Literate	Relevant Education and Experience
			Haggis has extensive financial markets and public board experience having served on the Board of Directors of Canadian Tire Bank until March 30, 2012. He was a director and Chair of the Investment Committee of the Insurance Corporation of British Columbia and currently serves as an advisor to the committee. He was also Chair of the Audit Committee of C.A. Bancorp and Prime Restaurants Royalty Income Fund and was Chair of Canadian Pacific Railway. Currently he is on the Board of Pure Industrial Real Estate Trust, a director of Sunshine Village Corp, a private Alberta company and is Chairman of Alberta Enterprise Corp. Mr. Haggis holds a Bachelor of Arts degree from the University of Western Ontario and is certified as a Chartered Director through the Directors College at McMaster University.
Stephen Balog Alberta, Canada	Yes	Yes	President, West Butte Management Inc., a private consulting company that provides technical and business advisory services to oil and gas operators. Formerly Principal of Alconsult International Ltd., and prior thereto President, Chief Operating Officer and a Director of Tasman Exploration Ltd. from 2001 to June, 2007. Mr. Balog has extensive oil and gas industry experience in the management and operation of senior and junior production companies. He was a key contributor to the development and use of the Canadian Oil & Gas Evaluation Handbook as an industry standard for reserves evaluation, and has previously served on the Petroleum Advisory Committee, Alberta Securities Commission.
Jill T. Angevine Alberta, Canada	Yes	Yes	Vice President and Portfolio Manager at Matco Financial Inc. (an independent, privately held asset management firm) since October 2013. Independent businesswoman from September 2011 until October 2013 and prior thereto, Vice President and Director, Institutional Research at FirstEnergy Capital Corp. (a financial advisory and investment services provider in the energy market).

Pre-Approval of Policies and Procedures

We have adopted policies and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by PricewaterhouseCoopers LLP as set forth in item 22 of the Audit Committee charter, which is reproduced below under the heading "*Audit Committee Charter*". The Audit Committee has approved the provision of a specified list of audit and permitted non-audit services that the audit committee believes to be typical, reoccurring or otherwise likely to be provided by PricewaterhouseCoopers LLP during the current fiscal year. The list of services is sufficiently detailed as to the particular services to be provided to ensure that the audit committee knows precisely what services it is being asked to pre-approve and it is not necessary for any member of management to make a judgment as to whether a proposed service fits within pre-approved services.

AUDIT COMMITTEE CHARTER

The following is a summary of our Audit Committee Charter approved by the Board of Directors.

Purpose

The primary function of the Audit Committee is to assist the Board of Directors of AOG in fulfilling its responsibilities by reviewing: the financial reports and other financial information provided by AOG to any governmental body or the public; AOG's systems of internal controls regarding finance, accounting, legal compliance and ethics that management and the Board have established; and AOG's auditing, accounting and financial reporting processes generally. Consistent with this function, the Audit Committee should endeavour to encourage continuous improvement of, and should endeavour to foster adherence to, AOG's policies, procedures and practices at all levels. In performing its duties, the external auditor is to report directly to the Audit Committee.

The Audit Committee's primary objectives are:

1. To assist directors meet their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of AOG and related matters;

2. To provide better communication between directors and external auditors;

3. To assist the Board's oversight of the auditor's qualifications and independence;

4. To assist the Board's oversight of the credibility, integrity and objectivity of financial reports;

5. To strengthen the role of the outside directors by facilitating discussions between directors on the Audit Committee, management and external auditors;

6. To assist the Board's oversight of the performance of the Corporation's internal audit function and independent auditors; and

7. To assist the Board's oversight of the Corporation's compliance with legal and regulatory requirements.

Composition

The Audit Committee shall be comprised of three or more directors as determined by the Board of Directors, none of whom are members of management of AOG and all of whom are "independent" (as such term is defined in: (a) National Instrument 52-110 — *Audit Committees* ("**NI 52-110**"); and (b) Section 303A.02 of the Corporate Governance Rules of the New York Stock Exchange). All of the members of the Audit Committee shall be "financially literate". The Board of Directors has adopted the definition for "financial literacy" used in NI 52-110. Audit Committee members may enhance their familiarity with finance and accounting by participating in educational programs conducted by AOG or an outside consultant. In addition, at least one member of the Audit Committee must have accounting or related financial management expertise, as the Corporation's Board of Directors interprets such qualification in its business judgment.

The members of the Audit Committee shall be elected by the Board of Directors and remain as members of the Audit Committee until their successors shall be duly elected and qualified. Unless a Chair is elected by the full Board of Directors, the members of the Audit Committee may designate a Chair by majority vote of the full Audit Committee membership.

In connection with its annual review procedures, the Board will determine whether any member or proposed nominee for the Audit Committee serves on the Audit Committees of more than three public companies. To the extent that any member or proposed nominee of AOG serves on the Audit Committees of more than three public companies, the Board will make a determination as to whether such simultaneous services would impair the ability of such member to effectively serve on AOG's Audit Committee and will disclose such determination in AOG's annual information circular and annual report on Form 40-F filed with the Securities and Exchange Commission.

Meetings

The Audit Committee shall meet at least four times annually, or more frequently as circumstances dictate. As part of its job to foster open communication, the Audit Committee should meet at least annually with management, internal auditors and the independent auditors in separate executive sessions to discuss any matters that the Audit Committee or each of these groups believe should be discussed privately. In addition, the Audit Committee or at least its Chair should meet with the independent auditors and management quarterly to review AOG's financials consistent with Section 4 below. The Audit Committee should also meet with management and independent auditors on an annual basis to review and discuss annual financial statements and the management's discussion and analysis of financial conditions and results of operations.

A quorum for meetings of the Audit Committee shall be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Audit Committee shall be the same as those governing the Board.

Responsibilities and Duties

To fulfill its responsibilities and duties, the Audit Committee shall endeavour to:

Documents/Reports Review

1. Review and update this Charter periodically, at least annually, as conditions dictate.

2. Review the organization's annual and interim financial statements, MD&A, earnings press releases and any reports or other financial information submitted to any governmental body or the public, including any certification, report, opinion or review rendered by the independent auditors.

3. Review the reports to management prepared by the independent auditors and management's responses.

4. Review with financial management and the independent auditors the quarterly financial statements prior to their filing or prior to the release of earnings. The Chair of the Audit Committee may represent the entire Audit Committee for purposes of this review.

5. Review significant findings during the year, including the status of previous significant audit recommendations.

6. Periodically assess the adequacy of procedures for the review of corporate disclosure that is derived or extracted from the financial statements.

7. Periodically discuss guidelines and policies to govern the processes by which the Chief Executive Officer and senior management assess and manage the Corporation's exposure to risk.

8. Report regularly to the Board any issues that arise with respect to the quality or integrity of the Corporation's financial statements, compliance with legal or regulatory requirements, performance and independence of the Corporation's auditors, or performance of the internal audit function.

9. To prepare, if required, an Audit Committee report to be included in AOG's annual information circular and proxy statement.

10. Preparing an annual performance evaluation of the Audit Committee.

11. At least annually, obtaining and reviewing the report by the independent auditors describing AOG's internal quality control procedures, any material issues raised by the most recent interim quality-control review, or peer review, of AOG or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the firm, and any steps to deal with any such issues.

Independent Auditors

12. Recommend to the Board the external auditors to be nominated for appointment by the Shareholders.

13. Approve the compensation of the external auditors.

14. On an annual basis, the Audit Committee should review and discuss with the auditors all significant relationships the auditors have with AOG to determine the auditors' independence. In addition, the Audit Committee will ensure the rotation of the lead audit partner every five years and, in order to ensure continuing auditor independence, consider the rotation of the audit firm itself.

15. Review and, as appropriate, resolve any material disagreements between management and the independent auditors and review, consider and make a recommendation to the Board regarding any proposed discharge of the auditors when circumstances warrant.

16. When there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change.

17. Periodically consult with the independent auditors, without the presence of management, about internal controls and the fullness and accuracy of the organization's financial statements.

18. Oversee the establishment of an internal audit function.

19. Periodically assess the Corporation's internal audit function, including the Corporation's risk management processes and system of internal controls.

20. Review the audit scope and plan of the independent auditor.

21. Oversee the work of the external auditors engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for AOG.

22. Pre-approve the completion of any non-audit services by the external auditors and determine which non-audit services the external auditor is prohibited from providing. The Audit Committee may delegate to one or more members of the Audit Committee authority to pre-approve non-audit services in satisfaction of this requirement and if such delegation occurs, the pre-approval of non-audit services by the Audit Committee member to whom authority has been delegated must be presented to the Audit Committee at its first scheduled meeting following such pre-approval. The Audit Committee shall be entitled to adopt specific policies and procedures for the engagement of non-audit services if:

    (a) the pre-approval policies and procedures are detailed as to the particular service;

    (b) the Audit Committee is informed of each non-audit service; and

    (c) the procedures do not include delegation of the Audit Committee's responsibilities to management.

    The Audit Committee will satisfy the pre-approval requirement set forth in this paragraph 22 if:

    (a) the aggregate amount of all non-audit services that were not pre-approved is reasonably expected to constitute no more than 5% of the total amount of fees paid by AOG and its subsidiary entities to the auditors during the fiscal year in which the services are provided;

    (b) AOG or the subsidiary entity, as the case may be, did not recognize the services as non-audit services at the time of the engagement;

    (c) the services are promptly brought to the attention of the Audit Committee and approved, prior to completion of the audit, by the Audit Committee or by one or more of its members to whom authority to grant such approvals has been delegated by the Audit Committee; and

23. Review, set and approve hiring policies relating to staff of current and former auditors.

Financial Reporting Processes

24. In consultation with the independent auditors, annually review the integrity of the organization's financial reporting processes, both internal and external.

25. In consultation with the independent auditors, consider annually the quality and appropriateness of the Corporation's accounting principles as applied in its financial reporting.

26. Consider and approve, if appropriate, major changes to AOG's auditing and accounting principles and practices as suggested by the independent auditors or management.

27. Review risk management policies and procedures of AOG (i.e., litigation and insurance).

Process Improvement

28. Request reporting to the Audit Committee by each of management and the independent auditors of any significant judgments made in the management's preparation of the financial statements and the view of each group as to appropriateness of such judgments.

29. Following completion of the annual audit, review separately with each of management and the independent auditors any significant difficulties encountered during the course of the audit, including any restrictions on the scope of work or access to required information.

30. Review any significant disagreements among management and the independent auditors in connection with the preparation of the financial statements.

31. Review with the independent auditors and management the extent to which changes or improvements in financial or accounting practices, as approved by the Audit Committee, have been implemented. (This review should be conducted at an appropriate time subsequent to implementation of changes or improvements, as decided by the Audit Committee.)

32. Conduct and authorize investigations into any matters brought to the Audit Committee's attention and within the Audit Committee's scope of responsibilities. The Audit Committee shall be empowered to retain and to approve compensation for any independent counsel and other professionals to assist in the conduct of any investigation.

33. Review the systems that identify and manage principal business risks.

34. Establish a procedure for:

    (a) the receipt, retention and treatment of complaints received by AOG regarding accounting, internal accounting controls or auditing matters; and

    (b) the confidential, anonymous submission by employees of AOG of concerns regarding questionable accounting or auditing matters;

    which procedure shall be set forth in a "whistle blower program" to be adopted by the Audit Committee in connection with such matters.

Ethical and Legal Compliance

35. Establish, review and update periodically a Code of Ethical Conduct and ensure that management has established a system to enforce this code.

36. Review management's monitoring of AOG's compliance with the organization's Ethical Code.

37. In consultation with the auditors, consider the review system established by management regarding the Corporation's financial statements, reports and other financial information disseminated to governmental organizations and the public in the context of the applicable legal requirements.

38. On at least an annual basis, review with AOG's auditors or counsel, as appropriate, any legal matters that could have a significant impact on the organization's financial statements, AOG's compliance with applicable laws and regulations and inquiries received from regulators or government agencies.

39. Review with the organization's counsel legal compliance matters including the trading policies of securities.

Other

40. Perform any other activities consistent with this Charter, AOG's by-laws and governing law, as the Audit Committee or the Board of Directors deems necessary or appropriate.

41. In connection with the performance of its responsibilities as set forth above, the Audit Committee shall have the authority to engage outside advisors and to pay outside auditors and advisors.

AUDIT SERVICE FEES

Auditor Services Fees

The following table discloses fees billed to us by our auditors, PricewaterhouseCoopers LLP.

Type of Service Provided	2016	2015
Audit Fees(1)	$263,000	$276,800
Audit-Related Fees(2)	45,000	60,000
Tax Fees(3)	16,500	25,000
Other Fees(4)	39,900	-
Total	$364,400	$361,800

Notes:

(1) "Audit Fees" include fees necessary to perform the annual audit of the Corporation's consolidated financial statements.
(2) "Audit-Related Fees" include services that are traditionally performed by the auditor. These audit-related services include quarterly reviews of the Corporation's consolidated financial statements.
(3) "Tax Fees" include fees for all tax services other than those included in "Audit Fees" and "Audit-Related Fees". This category includes fees for tax compliance, tax planning and general tax advice, including the preparation and filing of Scientific Research & Experimental Development Tax Credits.
(4) "Other Fees" represents fees related to the Offering.

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 with respect to the pricing and taxation of oil and natural gas, including the governments of Canada and Alberta, all of which investors in the oil and gas industry should carefully consider. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments governments may enact in the future. The following comprises some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in western Canada.

Pricing and Marketing

Oil

In Canada, producers of oil 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, regional market and transportation issues also influence prices. 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 licence from the NEB. The NEB underwent a consultation process to update the regulations governing the issuance of export licences. The updating process was 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. The *Regulations Amending the National Energy Board Act Part VI (Oil and Gas) Regulations* came into effect on July 31, 2015 and provide the requirements for obtaining long-term licences.

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 m^3 per day) must be made pursuant to an NEB order. Exporters are required to obtain an export license from the NEB for natural gas export contracts of a longer duration (to a maximum of 40 years) or that deal with larger quantities of natural gas.

The North American Free Trade Agreement

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. The new administration in the United States has indicated an intention to seek renegotiation of NAFTA, the impact of which on the oil and gas industry is uncertain.

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, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands where the Crown does not hold the mineral rights 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 are carved out of the working interest owner's interest, from time to time, through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests or net carried interests.

Occasionally the governments of the western Canadian provinces 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.

The Canadian federal government has signaled that it will *inter alia* phase out subsidies for the oil and gas industry, which include only allowing the use of the Canadian Exploration Expenses tax deduction in cases of successful exploration, implementing stringent reviews for pipelines and establishing a pan-Canadian framework for combating climate change. These changes could affect earnings of companies operating in the oil and natural gas industry.

Alberta

In Alberta, the Crown owns 81% of the province's mineral rights. The remaining 19% are 'freehold' mineral rights owned by the federal government on behalf of First Nations or in National Parks, and by individuals and companies. Provincial government royalty rates apply to Crown-owned mineral rights. On January 29, 2016, the Government of Alberta released and accepted the Royalty Review Advisory Panel's recommendations, which outlined the implementation of a "Modernized Royalty Framework" for Alberta (the "**MRF**"). The MRF formally took effect on January 1, 2017 for wells drilled after this date. Wells drilled prior to January 1, 2017 will continue to be governed by the "New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) (the "**Alberta Royalty Framework**") for a period of 10 years until January 1, 2027. The MRF is structured in three phases: (i) Pre-Payout; (ii) Mid-Life; and (iii) Mature. During the Pre-Payout phase, a fixed 5% royalty will apply until the well reaches payout. Well payout occurs when the cumulative revenue from a well is equal to the Drilling and Completion Cost Allowance (determined by a formula that approximates drilling and completion costs for wells based on total depth, length, and proppant placed). The new royalty rate for Pre-Payout under the MRF will be payable on gross revenue generated from all production streams (oil, gas, and natural gas liquids), eliminating the need to label a well as "oil" or "gas". Post-payout, the Mid-Life phase will apply a higher royalty rate than the Pre-Payout phase. Depending on the commodity price of the substance the well is producing, the royalty rate could range from 5% - 40%. The metrics for calculating the Mid-Life phase royalty are based on commodity prices and are intended, on average, to yield the same internal rate of return as under the Alberta Royalty Framework. In the Mature phase of the MRF, once a well reaches the tail end of its cycle and production falls below a Maturity Threshold, currently the equivalent of 194 m^3 (40 barrels of oil equivalent per day or 345,500 m^3 of gas per month), the royalty rate will move to a sliding scale (based on volume and price) with a minimum royalty rate of 5%. The downward adjustment of the royalty rate in the Mature phase is intended to account for the higher per-unit fixed cost involved in operating an older well.

On July 11, 2016, the Government of Alberta released details of the Enhanced Hydrocarbon Recovery Program and the Emerging Resources Program. These programs, that came into effect on January 1, 2017, are a part of the MRF and account for the higher costs associated with enhanced recovery methods and with developing emerging resources in an effort to make difficult investments economically viable and to increase royalties. Certain eligibility criteria must be satisfied in order for a proposed project to fall under each program. Enhanced recovery scheme applications can be submitted to the Alberta Energy Regulator ("**AER**").

Oil sands projects are also subject to Alberta's royalty regime. The MRF does not change the oil sands royalty framework, however, the Government of Alberta plans to increase transparency in the method and figures by which the royalties are calculated. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1% and 9% depending on the market price of oil, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil at Cushing, Oklahoma. Rates are 1% when the market price of oil is less than or equal to $55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of between 1% and 9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above $55 up to 40% when oil is priced at $120 or higher.

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.

Royalties, for wells drilled prior to January 1, 2017 are paid pursuant to the Alberta Royalty Framework until January 1, 2027. Royalty rates for conventional oil are set by a single sliding scale 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 depends on the price of each of the components of the gas stream, the productivity of the well, its acid gas factor and the depth of the producing zone. These factors are employed on a sliding scale formula to determine the natural gas royalty rate per well with the maximum royalty payable under the royalty regime set at 36% and a minimum royalty rate of 5%.

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 lands where the Crown does not hold the rights to mines and minerals 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 freehold mineral title properties.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. For example, the Innovative Energy Technologies Program (the "**IETP**") has the stated objectives of increasing recovery from oil and 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 IETP 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 (the "**Emerging Resource and Technologies Initiative**"). These initiatives apply to wells drilled before January 1, 2017, for a ten-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.

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, licences, 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 licence.

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 licences issued after January 1, 2009 at the conclusion of the primary term of the lease or licence.

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 gas operations and remain in good standing with the applicable provincial regulator, producers 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 environmental regulation under a variety of Canadian federal, provincial, territorial and municipal laws and regulations, 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 gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability and the imposition of material fines and penalties. In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and greenhouse gas ("**GHG**") emissions, may impose further requirements on operators and other companies in the oil and natural gas industry.

Federal

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

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 environmental 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.

On June 20, 2016, the Federal Government launched a review of current environmental and regulatory processes with a focus on rebuilding trust in the environmental assessment processes, modernizing the NEB, and introducing modernized safeguards to both the *Fisheries Act* and the *Navigation Protection Act*. An Expert Panel has been convened and is expected to complete its work by March 31, 2017. At such time, the Minister of Environment and Climate Change will consider the recommendations in the Panel’s report and identify next steps to improve federal environmental processes, which is expected to take place during the summer/fall of 2017. Until this process is complete, the Federal Government's interim principles released January 27, 2016 will continue to guide decision-making authorities for projects currently undergoing environmental assessment. The Federal Government has not provided any indication on what changes—if any—will be implemented or when, but increased delays and uncertainty surrounding the environmental assessment process should be expected for large projects.

In a further development, on November 29, 2016, the Government of Canada announced that it would introduce legislation by spring 2017 to formalize a moratorium for crude oil tankers on British Columbia's north coast. It is unclear how the proposed moratorium may affect ongoing LNG export projects currently under consideration and development. On the same day, the Government of Canada also approved, subject to a number of conditions, the Trans Mountain Pipeline system expansion backed by Kinder Morgan Canada as well as the replacement of Enbridge Inc.'s plan to replace its Line 3 pipeline system, while also rejecting Enbridge Inc.'s proposed Northern Gateway project. On January 11, 2017, the Government of British Columbia confirmed that the conditions to the approval of the Trans Mountain Pipeline have been satisfied. Additionally, the new administration in the United States has indicated a willingness to revisit other pipeline projects that had been previously rejected.

Alberta

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 ("**IRMS**"). The IRMS method to natural resource management provides for engagement and consultation with stakeholders and the public and examines the cumulative impacts of development on the environment and communities, by incorporating the management of all resources, including energy, minerals, land, air, water and biodiversity. While the AER is the primary regulator for energy development, several other governmental departments and agencies may be involved in land use issues, including Alberta Environment and Parks, Alberta Energy, the Policy Management Office, the Aboriginal Consultation Office and the Land Use Secretariat.

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 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, licences, 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 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 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.

Phase 1 Consultation of the North Saskatchewan Region Plan ("**NSRP**") has been completed and the Regional Advisory Council is currently preparing its Recommendation to Government report. The NSRP is located in central Alberta and is approximately 85,780 square kilometres in size and affects activities in central Alberta, and encompasses an area between the province's borders with British Columbia and Saskatchewan. The Upper Peace Region Plan, Lower Peace Region Plan, Red Dear Region Plan and Upper Athabasca Region Plan have not been started.

Liability Management Rating Programs

Alberta

In Alberta, the AER administers the Licensee Liability Rating Program (the "**AB LLR Program**"). The AB LLR Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. Alberta's *Oil and Gas Conservation Act (*"***OGCA***"*)* 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 ("**WIP**") becomes defunct or is unable to meet its obligations. 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 to 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. The AER publishes the liability management rating for each licensee on a monthly basis.

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 gas companies in Alberta that are required to post security. The Changes affect the deemed parameters and costs used in the formula that calculates the ratio of deemed liabilities to deemed assets under the AB LLR Program, increasing a licensee's deemed liabilities and rendering the industry average netback factor more sensitive to asset value fluctuations. The Changes stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

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

1. The AER will consider and process all applications for licence eligibility under *Directive 067: Applying for Approval to Hold EUB Licences* as non-routine and may exercise its discretion to refuse an application or impose terms and conditions on a licencee eligibility approval if appropriate in the circumstances.

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

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

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

1. The licensee already has an LMR of 2.0 or higher;

2. The acquisition will improve the licensee's LMR to 2.0 or higher; or

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

The AER provided no indication of what other means would be considered. The Alberta Court of Appeal heard the appeal of the *Redwater* decision on October 11, 2016, with the Court reserving its decision.

The AER implemented the Inactive Well Compliance Program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under *Directive 013: Suspension Requirements for Wells* ("***Directive 013***"). The IWCP applies to all inactive wells that are noncompliant with *Directive 013* as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of *Directive 013* within 5 years. As of April 1, 2015, each licensee is required to bring 20% of its inactive wells into compliance every year, either by reactivating or by suspending the wells in accordance with *Directive 013* or by abandoning them in accordance with *Directive 020: Well Abandonment*. The list of current wells subject to the IWCP is available on the AER's Digital Data Submission system. The AER announced that from April 1, 2015 to April 1, 2016, the number of noncompliant wells subject to the IWCP fell from 25,792 to 17,470, with 76% of licensees operating in the province having met their annual quota.

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.

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.

As 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), the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction in GHG emissions from 2005 levels by 2020; however, the GHG emission reduction targets are not binding. In May 2015, Canada submitted its Intended Nationally Determined Contribution ("**INDC**") to the UNFCCC. INDCs were communicated prior to the 2015 United Nations Climate Change Conference, held in Paris, France, which led to the Paris Agreement that came into force November 4, 2016 (the "**Paris Agreement**"). Among other items, the Paris Agreement constitutes the actions and targets that individual countries will undertake to help keep global temperatures from rising more than 2° Celsius and to pursue efforts to limit below 1.5° Celsius. The Government of Canada ratified the Paris Agreement on December 12, 2016, and pursuant to the agreement, Canada's INDC became its Nationally Determined Contributions ("**NDC**"). As a result, the Government of Canada replaced its INDC of a 17% reduction target established in the Copenhagen Accord with an NDC of 30% reduction below 2005 levels by 2030.

On June 29, 2016, the North American Climate, Clean Energy and Environment Partnership was announced among Canada, Mexico and the United States, which announcement included an action plan for achieving a competitive, low-carbon and sustainable North American economy. The plan includes setting targets for clean power generation, committing to implement the Paris Agreement, setting out specific commitments to address certain short-lived climate pollutants, and the promotion of clean and efficient transportation.

Additionally, on December 9, 2016, the Government of Canada formally announced the Pan-Canadian Framework on Clean Growth and Climate Change. As a result, the federal government will implement a Canada-wide carbon pricing scheme beginning in 2018. This may be implemented through either a cap and trade system or a carbon tax regime at the option of each province or territory. The federal government will impose a price on carbon of $10 per tonne on any province or territory which fails to implement its own system by 2018. This amount will increase by $10 annually until it reaches $50 per tonne in 2022 at which time the program will be reviewed.

In general, there is some uncertainty with regard to the impacts of federal or provincial climate change and environmental laws and regulations, as it is currently not possible to predict the extent of future requirements. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact on the Corporation's operations and cash flow.

Alberta

As part of its efforts to reduce GHG emissions, Alberta introduced legislation to address GHG emissions: the *Climate Change and Emissions Management Act* (the "***CCEMA***") 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 GHG emissions 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. As of 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.

A Regulated Emitter can meet its 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 greening 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. On June 7, 2016, the *Climate Leadership Implementation Act* ("***CLIA***") was passed into law. The *CLIA* enacted the *Climate Leadership Act* ("***CLA***") introducing a carbon tax on all sources of GHG emissions, subject to certain exemptions. An initial economy-wide levy of $20 per tonne was implemented on January 1, 2017, increasing to $30 per tonne in January of 2018. All fuel consumption—including gasoline and natural gas—will be subject to the levy, with certain exemptions, and directors of a corporation may be held jointly and severally liable with a corporation when the corporation fails to remit an owed carbon levy. Regulated Emitters will remain subject to the *SGER* framework until the end of 2017; upon the expiry of the *SGER*, the Government of Alberta intends to transition to a proposed *Carbon Competitiveness Regulation*, in which sector specific output-based carbon allocations will be used to ensure competitiveness. A 100 megatonne per year limit for GHG emissions was implemented 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. Regulations accompanying the *CLIA* have not yet been released.

The passing of the *CLIA* is the first step towards executing the Climate Leadership Plan (other legislation is still pending). In addition to enacting the *CLA*, the *CLIA* also enacted the *Energy Efficiency Alberta Act*, which enables the creation of Energy Efficiency Alberta, a new Crown corporation to support and promote energy efficiency programs and services for homes and businesses.

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

RISK FACTORS

The following is a summary of certain risk factors relating to the business of Advantage. The following information is a summary only of certain risk factors and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this annual information form.

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision.

Prices, Markets and Marketing

Numerous factors beyond the Corporation's control do, and will continue to, affect the marketability and price of oil and natural gas acquired, produced, or discovered by the Corporation. The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire capacity on pipelines that deliver natural gas to commercial markets or contract for the delivery of crude oil by rail. Deliverability uncertainties related to the distance the Corporation's reserves are from pipelines, railway lines, processing and storage facilities; operational problems affecting pipelines, railway lines and facilities; and government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect the Corporation.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic and political conditions in the United States, Canada, Europe, China and emerging markets, the actions of the Organization of the Petroleum Exporting Countries ("**OPEC**"), governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply and demand of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and the Corporation's ability to access such markets. Oil prices are expected to remain volatile as a result of global excess supply due to the increased growth of shale oil production in the United States, the decline in global demand for exported crude oil commodities, OPEC's recent decisions pertaining to the oil production of OPEC member countries, and non-OPEC member countries' decisions on production levels, among other factors. A material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices.

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

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries and ongoing credit and liquidity concerns. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural 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 return on, acquisitions and development and exploitation projects.

In addition, bank borrowings available to the Corporation may, in part, be determined by the Corporation's borrowing base. A sustained material decline in 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.

See "*Risk Factors - Weakness in the Oil and Gas Industry*".

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 emerging economies, market volatility and disruptions in Asia, sovereign debt levels and political upheavals 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 the case of Alberta, at the provincial level, and the resultant uncertainty surrounding regulatory, tax, royalty changes and environmental regulation that have been announced or 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 downward price pressure on oil and gas produced in Western Canada and 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, rendering certain reserves uneconomic. In addition, lower commodity prices have restricted, and are anticipated to continue to restrict, the Corporation's cash flow resulting in a reduced capital expenditure budget. Consequently, 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 or if it is able to do so, it may be on unfavourable and highly dilutive terms.

Political Uncertainty

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. During the recent presidential campaign in the United States a number of election promises were made and the new American administration has begun taking steps to implement certain of these promises. Included in the actions that the administration has discussed are the renegotiation of the terms of the North American Free Trade Agreement, withdrawal of the United States from the Trans-Pacific Partnership, imposition of a tax on the importation of goods into the United States, reduction of regulation and taxation in the United States, and introduction of laws to reduce immigration and restrict access into the United States for citizens of certain countries. It is presently unclear exactly what actions the new administration in the United States will implement, and if implemented, how these actions may impact Canada and in particular the oil and gas industry. Any actions taken by the new United States administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and gas companies, including the Corporation.

In addition to the political disruption in the United States, in 2016 the citizens of the United Kingdom voted to withdraw from the European Union and the Government of the United Kingdom has begun taken steps to implement such withdrawal. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement it could have an adverse effect on the Corporation's ability to market its products internationally, increase costs for goods and services required for the Corporation's operations, reduce access to skilled labour and negatively impact the Corporation's business, operations, financial conditions and ultimately the market value of the Common Shares.

Geo-Political Risks

Political events throughout the world that cause disruptions in the supply of oil continuously affect the marketability and price of oil and natural gas acquired or discovered by the Corporation. Conflicts, or conversely peaceful developments, arising outside of Canada, including changes in political regimes or the parties in power, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and result in a reduction of the Corporation's net production revenue.

In addition, the Corporation's oil and natural gas properties, wells and facilities could be the subject of a terrorist attack. If any of the Corporation's properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have insurance to protect against the risk from terrorism.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, the Corporation's existing reserves, and the production from them, will decline over time as the Corporation produces from such reserves. A future increase in the Corporation's reserves will depend on both the ability of the Corporation to explore and develop its existing properties and its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Corporation will be able continue to find satisfactory properties to acquire or participate in. Moreover, management of the Corporation may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participation uneconomic. There is also no assurance that the Corporation will discover or acquire further commercial quantities of oil and natural gas.

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

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

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment and personal injury. Particularly, the Corporation may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation.

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

As is standard industry practice, the Corporation is not fully insured against all risks, nor are all risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event, the Corporation could incur significant costs.

Gathering and Processing Facilities, Pipeline Systems and Rail

The Corporation delivers its products through gathering and processing facilities, pipeline systems and, in certain circumstances, by rail. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines could result in the Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation's production. The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to transport produced oil and gas to market. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the Corporation's production, operations and financial results. As a result, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays or uncertainty in constructing new infrastructure systems and facilities could harm the Corporation's business and, in turn, the Corporation's financial condition, operations and cash flows. In addition, the federal government has signaled that it plans to review the National Energy Board approval process for large federally regulated projects. This may cause the timeframe for project approvals to increase for current and future applications.

Following major accidents in Lac-Megantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Board have recommended additional regulations for railway tank cars carrying crude oil. In June 2015, as a result of these recommendations, the Government of Canada passed the *Safe and Accountable Rail Act* which increased insurance obligations on the shipment of crude oil by rail and imposed a per tonne levy of $1.65 on crude oil shipped by rail to compensate victims and for environmental cleanup in the event of a railway accident. In addition to this legislation, new regulations have implemented the TC-117 standard for all rail tank cars carrying flammable liquids which formalized the commitment to retrofit, and eventually phase out DOT-111 tank cars carrying crude oil. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and adds additional costs to the transportation of crude oil by rail. On July 13, 2016, the Minister of Transport (Canada) issued *Protective Direction No. 38*, which directed that the shipping of crude oil on DOT-111 tank cars end by November 1, 2016. Tank cars entering Canada from the United States will be monitored to ensure they are compliant with *Protective Direction No. 38*.

A portion of the Corporation's production may, from time to time, be processed through facilities owned by third parties and over which the Corporation does not have control. From time to time, these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a materially adverse effect on the Corporation's ability to process its production and deliver the same for sale.

Pipeline Systems

The interruption of firm pipeline transportation has and may continue to affect the oil and natural gas industry and limit the ability to fully produce and market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems may also affect the ability to export oil and natural gas. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators may also affect the Corporation's production, operations and financial results. The Corporation's production could be adversely impacted by both firm and interruptible transportation service curtailments on TransCanada's NGTL system.

Project Risks

The Corporation manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost overruns could make a project uneconomic. The Corporation's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Corporation's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;

- the availability of storage capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling, hydraulic fracturing, and waterfloods or the Corporation's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Corporation could be unable to execute projects on time, on budget, or at all and may be unable to market the oil and natural gas that it produces effectively.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this document are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves and the future net cash flows from such estimated reserves 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; and
- 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 oil 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 reserves will vary from estimates and such variations could be material.

The estimation of proved reserves that may be developed and produced in the future is often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas are often estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves. Such variations could be material.

In accordance with applicable securities laws, the Corporation's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from the Corporation's oil and natural gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom and contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and, except as may be specifically stated, has not been updated and therefore does not reflect changes in the Corporation's reserves since that date.

Hedging

From time to time, the Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that the Corporation engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Corporation's hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes or prices fall significantly lower than projected;
- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement;
- the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil and natural gas prices.

Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars or other currencies in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to other currencies. However, if the Canadian dollar declines in value compared to such fixed currencies, the Corporation will not benefit from the fluctuating exchange rate.

Terrorism and Sabotage

In addition to the risks outlined herein related to geopolitical developments, the Corporation’s oil and natural gas properties, wells and facilities could be subject to a terrorist attack or physical sabotage. While the Corporation's oil and gas properties are all located in Canada, a politically stable, developed nation, if any of the Corporation’s properties, wells or facilities are the subject of terrorist attack or sabotage it may have a material adverse effect on the Corporation’s business, financial condition, results of operations and prospects. The Corporation may not have adequate insurance to protect against such risks.

Credit Facility Arrangements

The Corporation currently has a credit facility and the amount authorized thereunder is dependent on the borrowing base determined by its lenders. The Corporation is required to comply with covenants under its credit facility which may, in certain cases, include certain financial ratio tests, which from time to time either affect the availability, or price, of additional funding and in the event that the Corporation does not comply with these covenants, the Corporation's access to capital could be restricted or repayment could be required. Events beyond the Corporation’s control may contribute to the failure of the Corporation to comply with such covenants. A failure to comply with covenants could result in the default under the Corporation's credit facility, which could result in the Corporation being required to repay amounts owing thereunder. Even if the Corporation is able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to the Corporation. If the Corporation is unable to repay amounts owing under credit facilities, the lenders under the credit facility could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. The acceleration of the Corporation's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Corporation's credit facility may impose operating and financial restrictions on the Corporation that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to the Corporation's securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

The amount authorized under the Credit Facilities is dependent on the borrowing base determined by its lenders. The lenders under the Credit Facilities use the Corporation's reserves, commodity prices, and other factors, to periodically determine the Corporation's borrowing base. There remains a substantial amount of uncertainty as to when and if commodity prices will recover. Commodity prices continue to be depressed and have fallen dramatically since 2014. Continued depressed commodity prices or further reductions in commodity prices could result in a reduction to the Corporation's borrowing base, reducing the funds available to the Corporation under the Credit Facilities. This could result in the requirement to repay a portion, or all, of the Corporation's indebtedness.

Forward-Looking Information May Prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on the Corporation's forward-looking information, and in particular, the guidance provided under "*General Development of the Business – Recent Developments*". 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. Additional information on the risks, assumption and uncertainties are found under "*Forward-Looking Statements*".

Substantial Capital Requirements

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, the Corporation's ability to do so is dependent on, among other factors:

- the overall state of the capital markets;
- the Corporation's credit rating (if applicable);
- commodity prices;
- interest rates;
- royalty rates;
- tax burden due to current and future tax laws; and
- investor demand for investments in the energy industry and the Corporation's securities in particular.

Further, if the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. The current conditions in the oil and gas industry have negatively impacted the ability of oil and gas companies to access additional financing. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The Corporation may be required to seek additional equity financing on terms that are highly dilutive to existing shareholders. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

Additional Funding Requirements

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and from time to time, the Corporation may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. Failure to obtain 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. Due to the conditions in the oil and gas industry and/or global economic and political volatility, the Corporation may from time to time have restricted access to capital and increased borrowing costs. The current conditions in the oil and gas industry have negatively impacted the ability of oil and gas companies to access additional financing.

As a result of global economic and political volatility, the Corporation may from time to time have restricted access to capital and increased borrowing costs. 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 revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, the Corporation's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of the Corporation's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Alternatively, any available financing may be highly dilutive to existing shareholders. 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.

Royalty Regimes

There can be no assurance that the provincial governments of the western provinces will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of the Corporation's projects. An increase in royalties would reduce the Corporation's earnings and could make future capital investments, or the Corporation's operations, less economic. On January 29, 2016, the Government of Alberta adopted a new royalty regime which took effect on January 1, 2017. See "*Industry Conditions – Royalties and Incentives*".

Management of Growth

The Corporation may be subject to growth related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Corporation to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of the Corporation to deal with this growth may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Reliance on Key Personnel

The Corporation's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have any key personnel insurance in effect for the Corporation. The contributions of the existing management team to the immediate and near term 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. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

Information Technology Systems and Cyber-Security

The Corporation has become increasingly dependent upon the availability, capacity, reliability and security of its information technology infrastructure and its ability to expand and continually update this infrastructure, to conduct daily operations. The Corporation depends on various information technology systems to estimate reserve quantities, process and record financial data, manage its land base, analyze seismic information, administer contracts with its operators and lessees and communicate with employees and third-party partners.

Further, the Corporation is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Corporation’s information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to the Corporation's business activities or our competitive position. Further, disruption of critical information technology services, or breaches of information security, could have a negative effect on the Corporation's performance and earnings, as well as on its reputation**.** The Corporation applies technical and process controls in line with industry-accepted standards to protect its information assets and systems; however, these controls may not adequately prevent cyber-security breaches. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on the Corporation’s business, financial condition and results of operations.

Market Price of Common Shares

The trading price of securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. The market price of the Common Shares may be volatile, which may affect the ability of holders to sell the Common Shares at an advantageous price. Market price fluctuations in the Common Shares may be due to the Corporation's operating results failing to meet the expectations of securities analysts or investors in any quarter, downward revision in securities analysts' estimates, governmental regulatory action, adverse change in general market conditions or economic trends, acquisitions, dispositions or other material public announcements by the Corporation or its competitors, along with a variety of additional factors, including, without limitation, those set forth under "*Forward-Looking Statements*". In addition, the market price for securities in the stock markets, including the TSX and the NYSE, has recently experienced significant price and trading fluctuations. These fluctuations have resulted in volatility in the market prices of securities that are often unrelated or disproportionate to changes in operating performance. Factors unrelated to the Corporation's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices or current perceptions of the oil and gas market. These broad market fluctuations may adversely affect the market prices of the Common Shares, and, as such, the price at which the Common Shares will trade cannot be accurately predicted.

Impact of Future Financings on Market Price

In order to finance future operations or acquisition opportunities, the Corporation may raise funds through the issuance of Common Shares or the issuance of debt instruments or securities convertible into Common Shares. The Corporation cannot predict the size of future issuances of Common Shares or the issuance of debt instruments or other securities convertible into Common Shares or the effect, if any, that future issuances and sales of the Corporation’s securities will have on the market price of the Common Shares.

Dilution

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

Competition

The petroleum industry is competitive in all of its phases. The Corporation competes with numerous other entities in the exploration, development, production and marketing of oil and natural gas. The Corporation's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. Some of these companies not only explore for, develop and produce oil and natural gas, but also carry on refining operations and market oil and natural gas on an international basis. As a result of these complementary activities, some of these competitors may have greater and more diverse competitive resources to draw on than the Corporation. The Corporation's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price, process, and reliability of delivery and storage

Hydraulic Fracturing

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

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

Variations in Foreign Exchange Rates and Interest Rates

World oil and natural gas prices are quoted in United States dollars. The Canadian/United States dollar exchange rate, which fluctuates over time, consequently affects the price received by Canadian producers of oil and natural gas. Material increases in the value of the Canadian dollar relative to the United States dollar will negatively affect the Corporation's production revenues. Accordingly, exchange rates between Canada and the United States could affect the future value of the Corporation's reserves as determined by independent evaluators. Although a low value of the Canadian dollar relative to the United States dollar may positively affect the price the Corporation receives for its oil and natural gas production, it could also result in an increase in the price for certain goods used for the Corporation's operations, which may have a negative impact on the Corporation's financial results.

To the extent that the Corporation engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Corporation may contract.

An increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt, resulting in a reduced amount available to fund its exploration and development activities, and if applicable, the cash available for dividends and could negatively impact the market price of the Common Shares.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with oil and gas industry operations. 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 environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental legislation, no assurance can be given that environmental compliance requirements will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. See "*Industry Conditions*". The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Corporation's costs, either of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, the Corporation will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities at the provincial and federal level. There can be no assurance that the Corporation will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake. In addition, certain federal legislation such as the *Competition Act* and the *Investment Canada Act* could negatively affect the Corporation's business, financial condition and the market value of its Common Shares or its assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity.

Insurance

The Corporation's involvement in the exploration for and development of oil and natural gas properties may result in the Corporation becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Corporation maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, certain risks are not, in all circumstances, insurable or, in certain circumstances, the Corporation may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Third Party Credit Risk

The Corporation 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 and other parties. In addition, the Corporation may be exposed to third party credit risk from operators of properties in which the Corporation has a working or royalty interest. In the event such entities fail to meet their contractual obligations to the Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may affect a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner. To the extent that any of such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in the Corporation being unable to collect all or portion of any money owing from such parties. Any of these factors could materially adversely affect the Corporation's financial and operational results.

Liability Management

Alberta has developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its obligation. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes to the required ratio of the Corporation's deemed assets to deemed liabilities or other changes to the requirements of liability management programs may result in significant increases to the Corporation's compliance requirement. In addition, the liability management system may prevent or interfere with the Corporation's ability to acquire or dispose of assets as both the vendor and the purchaser of oil and gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. The recent Alberta Court of Queen's Bench decision, *Redwater Energy Corporation (Re)* 2016 ABQB 278, found an operational conflict between the *Bankruptcy and Insolvency Act* and the AER's abandonment and reclamation powers when the licensee is insolvent. The AER appealed this decision and issued interim rules to administer the liability management program and until the Alberta Government can develop new regulatory measures to adequately address environmental liabilities. The decision from this appeal has not been released. There remains a great deal of uncertainty as to what new regulatory measures will be developed or what the impact of the court decision will have on other provinces. See "*Industry Conditions - Liability Management Rating Programs*".

Tax Horizon

It is expected, based upon current legislation, the projections contained in the Sproule Report and various other assumptions that no cash income taxes are to be paid by the Corporation prior to 2021. A lower level of capital expenditures than those contained in the Sproule Report or should the assumptions used by the Corporation prove to be inaccurate, the Corporation may be required to pay cash income taxes sooner than anticipated, which will reduce cash flow available to the Corporation.

Operational Dependence

Other companies operate some of the assets in which the Corporation has an interest. The Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others depends upon a number of factors that may be outside of the Corporation's control, including, but not limited to, the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

In addition, due to the current low and volatile commodity prices, many companies, including companies that may operate some of the assets in which the Corporation has an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which the Corporation has an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations the Corporation may be required to satisfy such obligations and to seek reimbursement from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, the Corporation potentially becoming subject to additional liabilities relating to such assets and the Corporation having difficulty collecting revenue due from such operators or recovering amounts owing to the Corporation from such operators for their share of abandonment and reclamation obligations. Any of these factors could have a material adverse affect on the Corporation's financial and operational results.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that a defect in the chain of title will not arise. The actual interest of the Corporation in properties may accordingly vary from the Corporation's records. If a title defect does exist, it is possible that the Corporation may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes, which affect the Corporation's title to the oil and natural gas properties the Corporation controls that could impair the Corporation's activities on them and result in a reduction of the revenue received by the Corporation.

Expiration of Licences and Leases

The Corporation's properties are held in the form of licences and leases and working interests in licences and leases. If the Corporation or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Corporation's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation considers acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the Corporation's ability to realize 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 diverting management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided by third parties and assets required to provide such services. In this regard, non-core assets may be periodically disposed of so 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 may realize less on disposition than their carrying value on the financial statements of the Corporation.

In addition, acquisitions of oil and gas properties or companies are based in large part on engineering, environmental and economic assessments made by the acquiror, independent engineers and consultants. These assessments include a series of assumptions regarding such factors as recoverability and marketability of oil and natural gas, environmental restrictions and prohibitions regarding releases and emissions of various substances, future prices of oil and gas, future operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the Corporation. All such assessments involve a measure of geologic, engineering, environmental and regulatory uncertainty that could result in lower production and reserves or higher operating or capital expenditures than anticipated. Although select title and environmental reviews are conducted prior to any purchase of resource assets, such reviews cannot guarantee that any unforeseen defects in the chain of title will not arise to defeat the Corporation's title to certain assets or that environmental defects, liabilities or deficiencies do not exist or are greater than anticipated. Such deficiencies or defects could adversely affect the value of the assets acquired and the Corporation's securities.

Climate Change

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases which may require the Corporation to comply with GHG emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the UNFCCC and a participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it would seek a 17% reduction in GHG emissions from 2005 levels by 2020; however, these GHG emission reduction targets were not binding. As a result of the UNFCCC adopting the Paris Agreement on December 12, 2015, which Canada ratified on October 3, 2016, the Government of Canada implemented new GHG emission reduction targets of a 30% reduction from 2005 levels by 2030. In addition, the Government of Canada announced it would implement a Canada wide price on carbon to further reduce its GHG emissions. In addition, on January 1, 2017 the CLA came into effect in the Province of Alberta introducing a carbon tax on almost all sources of GHG emissions at a rate of $20 per tonne, increasing to $30 per tonne in January 2018. The direct or indirect costs of compliance with these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Some of the Corporation's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition. See "*Industry Conditions - Climate Change Regulation*".

Aboriginal Claims

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

Issuance of Debt

From time to time, the Corporation may enter into transactions to acquire assets or shares of other entities. These transactions may be financed in whole or in part with debt, which may increase the Corporation's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Corporation may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time could impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Conflicts of Interest

Certain directors or officers of the Corporation may also be directors or officers of other oil and natural gas companies and as such may, in certain circumstances, have a conflict of interest. Conflicts of interest, if any, will be subject to and governed by procedures prescribed by the ABCA which require a director of officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the Corporation disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA. See "*Directors and Officers – Conflicts of Interest*".

Cost of New Technologies

The petroleum industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before the Corporation. There can be no assurance that the Corporation will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. If the Corporation does implement such technologies, there is no assurance that the Corporation will do so successfully. One or more of the technologies currently utilized by the Corporation or implemented in the future may become obsolete. In such case, the Corporation's business, financial condition and results of operations could be affected adversely and materially. If the Corporation is unable to utilize the most advanced commercially available technology, or is unsuccessful in implementing certain technologies, its business, financial condition and results of operations could also be adversely affected in a material way.

Waterflood

The Corporation undertakes or may undertake in the future certain waterflooding programs which involve the injection of water or other liquids into an oil reservoir to increase production from the reservoir and to decrease production declines. To undertake such waterflooding activities the Corporation needs to have access to sufficient volumes of water, or other liquids, to pump into the reservoir to increase the pressure in the reservoir. There is no certainty that the Corporation will have access to the required volumes of water. In addition, in certain areas there may be restrictions on water use for activities such as waterflooding. If the Corporation is unable to access such water it may not be able to undertake waterflooding activities, which may reduce the amount of oil and natural gas that the Corporation is ultimately able to produce from its reservoirs. In addition, the Corporation may undertake certain waterflood programs that ultimately prove unsuccessful in increasing production from the reservoir and as a result have a negative impact on the Corporation's results of operations.

Alternatives to and Changing Demand for Petroleum Products

Full conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and energy generation devices could reduce the demand for oil, natural gas and liquid hydrocarbons. The Corporation cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Corporation's business, financial condition, results of operations and cash flows.

Litigation

In the normal course of the Corporation's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, relating to personal injuries, including resulting from exposure to hazardous substances, property damage, property taxes, land and access rights, environmental issues, including claims relating to contamination or natural resource damages and contract disputes. The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Corporation, and as a result, could have a material adverse effect on the Corporation's assets, liabilities, business, financial condition and results of operations. Even if the Corporation prevails in any such legal proceedings, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from business operations, which could have an adverse affect on the Corporation's financial condition.

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, the Corporation may disclose confidential information relating to the business, operations or affairs of the Corporation. Although confidentiality agreements are generally signed by third parties prior to the disclosure of any confidential information, a breach could put the Corporation at competitive risk and may cause significant damage to its business. The harm to the Corporation's business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, the Corporation will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to its business that such a breach of confidentiality may cause.

Internal Controls

Effective internal controls are necessary for the Corporation to provide reliable financial reports and to help prevent fraud. Although the Corporation will undertake a number of procedures in order to help ensure the reliability of its financial reports, including those imposed on it under Canadian securities laws, the Corporation cannot be certain that such measures will ensure that the Corporation will maintain adequate control over financial processes and reporting. Failure to implement required new or improved controls, or difficulties encountered in their implementation, could harm the Corporation's results of operations or cause it to fail to meet its reporting obligations. If the Corporation or its independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in the Corporation's financial statements and harm the trading price of the Common Shares.

Income Taxes

The Corporation files all required income tax returns and believes that it is in full compliance with the provisions of the *Income Tax Act* (Canada) 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.

Income tax laws relating to the oil and natural gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects the Corporation. Furthermore, tax authorities having jurisdiction over the Corporation may disagree with how the Corporation calculates its income for tax purposes or could change administrative practices to the Corporation's detriment.

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) as well as skilled personnel trained to use such equipment in the areas where such activities will be conducted. Demand for such limited equipment and skilled personnel, or access restrictions, may affect the availability of such equipment and skilled personnel to the Corporation and may delay exploration and development activities.

Seasonality

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict the Corporation's ability to access its properties and cause operational difficulties. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding decreases in the demand for the goods and services of the Corporation.

Dividends

The Corporation has not paid any dividends on its outstanding shares. The amount of future cash dividends paid by the Corporation, if any, will be subject to the discretion of the board of directors of the Corporation and will depend on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends. See "*Dividend Policy*".

Expansion into New Activities

The operations and expertise of the Corporation's management are currently focused primarily on oil and gas production, exploration and development in the Western Canada Sedimentary Basin. In the future the Corporation may acquire or move into new industry related activities or new geographical areas, may acquire different energy related assets and as a result may face unexpected risks or alternatively, significantly increase the Corporation's exposure to one or more existing risk factors, which may in turn result in the Corporation's future operational and financial conditions being adversely affected.

DISCLOSURE PURSUANT TO THE REQUIREMENTS OF THE NEW YORK STOCK EXCHANGE

As a foreign private issuer listed on the NYSE, Advantage is not required to comply with most of the NYSE rules and listing standards and instead may comply with domestic Canadian requirements. Advantage is, however, required to comply with the following NYSE Rules: (i) Advantage must have an audit committee that satisfies the requirements of Rule 10A-3 under the United States Securities Exchange Act of 1934, as amended; (ii) the Chief Executive Officer must promptly notify the NYSE in writing after an executive officer becomes aware of any non-compliance with the applicable NYSE Rules; (iii) Advantage must submit an executed Section 303A annual written affirmation to the NYSE, as well as a Section 303A interim affirmation each time certain changes occurs to the audit committee; and (iv) Advantage must annually provide a brief description of any significant differences between its corporate governance practices and those followed by U.S. domestic issuers under NYSE listing standards. Advantage has reviewed the NYSE listing standards followed by U.S. domestic issuers listed under the NYSE and confirms that its corporate governance practices do not differ significantly from such standards.

ADDITIONAL INFORMATION

Additional information relating to the Corporation can be found on SEDAR at www.sedar.com and the Corporation's website at www.advantageog.com.

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Common Shares and securities authorized for issuance under equity compensation plans, will be contained in the Corporation's Information Circular for the most recent annual meeting of shareholders that involved the election of directors of Advantage. Additional financial information is provided for in the Corporation's Consolidated financial statements and management's discussion and analysis for the year ended December 31, 2016.

SCHEDULE "A"

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE (FORM 51-101F3)

Report of Management and Directors on Reserves Data and Other Information

Management of Advantage Oil & Gas Ltd. (the "**Company**") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves Committee of the board of directors of the Company has:

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

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

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

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator 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) *"Andy Mah"*
Andy Mah
President and Chief Executive Officer

(signed) *"Craig Blackwood"*
Craig Blackwood
Vice President, Finance and Chief Financial Officer

(signed) *"Ronald A. McIntosh"*
Ronald A. McIntosh
Director

(signed) *"Stephen Balog"*
Stephen Balog
Director

Dated the 2 day of March, 2017

SCHEDULE "B"

REPORT ON RESERVES DATA
BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR
(FORM 51-101F2)

Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor

To the board of directors of Advantage Oil & Gas Ltd. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2016. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2016, estimated using forecast prices and costs.

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

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

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

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2016, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)			
			Audited (M$)	Evaluated (M$)	Reviewed (M$)	Total (M$)
Sproule Associates Limited	December 31, 2016	Canada	-	$2,213,743	-	$2,213,743
Totals			-	$2,213,743	-	$2,213,743

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

7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.

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

EXECUTED as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta, Canada
February **7**, 2017

Original Signed by Alec Kovaltchouk, P. Geo.
Alec Kovaltchouk, P. Geo.
Vice-President, Geosciences

Original Signed by Cameron P. Six, P. Eng.
Cameron P. Six, P. Eng.
Chief Operating Officer and Director

Original Signed by Brent A. Hawkwood, P. Eng.
Brent A. Hawkwood, P. Eng.
Senior Petroleum Technologist