



ANNUAL INFORMATION FORM

YEAR ENDED DECEMBER 31, 2017

March 5, 2018

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SCHEDULES

- "A" – REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE
- "B" – REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

GLOSSARY OF TERMS

Selected Defined Terms

"**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 – 2017 – 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 certainty;

"**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" or "NGLs" 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;

"NGTL" means TransCanada Pipeline's natural gas gathering and transportation system in Alberta and northeastern British Columbia.

"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 Oil and Gas Information – Disclosure of Reserves Data*";

"**Sproule Report**" has the meaning ascribed thereto under the heading "*Statement of Reserves Data and Other Oil 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

<u>Crude Oil and Natural Gas Liquids</u>		<u>Natural Gas</u>	
bbls	barrels	Mcf	thousand cubic feet
Mbbls	thousand barrels	MMcf	million cubic feet
MMbbls	million barrels	bcf	billion cubic feet
NGLs	natural gas liquids	bcf/d	billion cubic feet per day
BOE or boe	means barrel of oil equivalent	Mcf/d	thousand cubic feet per day
MMboe	million barrels of oil equivalent	MMcf/d	million cubic feet per day
boe/d	barrels of oil equivalent per day	Mcfe	thousand cubic feet of natural gas equivalent, using the ratio of 6 Mcf of natural gas being equivalent to one bbl of oil
bbls/d	barrels of oil per day	MMcfe	million cubic feet of natural gas equivalent
		MMcfe/d	million cubic feet of natural gasequivalent per day
		MMbtu	million British Thermal Units
		GJ	Gigajoules
		GJ/d	Gigajoules per day
<u>Other</u>			
AECO	Alberta Energy Company's natural gas storage facility located at Suffield, Alberta		
GJ/d			
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 form 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).

<u>To Convert From</u>	<u>To</u>	<u>Multiply By</u>
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. Advantage believes 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, natural gas and NGL production levels;
- the size of the crude oil, natural gas and NGL reserves;
- projections of market prices and costs and supply and demand for crude oil, natural gas and NGLs;
- 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 2018, including the estimated amount of capital expenditures; and the focus of the Corporation's capital expenditures and operations, including the Corporation's drilling, completion 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 beyond 2018.

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, NGLs and natural gas; the impact of significant declines in market prices for crude oil, NGLs and natural gas; stock market volatility; changes to legislation and regulations, including environmental 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", which should not be considered as alternatives to, or more meaningful than "net income", "comprehensive income" or "cash provided by operating activities" as determined in accordance with GAAP. Management of the Corporation believes that these measures provide an indication of the results generated by the Corporation's principal business activities and provide useful supplemental information for analysis of the Corporation's operating performance and liquidity. 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.

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.

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, 2017, 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, 2015, 2016 and 2017 is outlined below. Unless the context otherwise requires, references to "we", "us", "our" or similar terms refer to the Corporation.

Three Year History

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. In 2016, Advantage began another significant expansion of the Glacier gas plant to increase processing capacity by 150 MMcf/d to a total of 400 MMcf/d.

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.

Credit Facilities

During the second quarter of 2016, Advantage renewed the borrowing base under its Credit Facilities at \$400 million. Advantage requested a reduction from the prior \$450 million borrowing base due to its strong balance sheet and estimated capital requirements for future growth.

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.

2017

2018 Capital Budget and Development Plan

On December 11, 2017, Advantage announced that its Board of Directors had approved a 2018 capital budget of \$175 million funded through cash flow to increase production to 260 MMcfe/d. The 2018 capital budget contemplates the completion of the Glacier gas plant expansion by the second quarter of 2018, completion and equipping of standing wells drilled during 2017, a 2018 drilling program and \$30 million for the advancement of delineation and development in the Valhalla, Wembley and Progress areas, including initial facility installation at Valhalla to transport additional higher liquids production for processing at Glacier.

Glacier Gas Plant

Construction on the Glacier gas plant expansion began in the second half of 2017. On December 11, 2017, Advantage announced planned capital investment at Glacier in 2018 of \$145 million, including \$35 million to complete the expansion of its Glacier gas plant. Completion of the Glacier gas plant expansion is anticipated by the second quarter of 2018 and will increase raw gas processing capacity from 250 mmcf/d to 400 mmcf/d with propane plus (C3+) liquids handling capacity increased to 6,800 bbls/d.

Credit Facilities

On October 20, 2017, the semi-annual redetermination of Advantage's credit facilities (the "Credit Facilities") was completed with no changes to the borrowing base of \$400 million, comprised of a \$20 million extendible revolving operating loan facility from one financial institution and a \$380 million extendible revolving loan facility from a syndicate of financial institutions.

TransCanada Pipelines ("TCPL")

In 2017, Advantage participated in TCPL's long term, fixed price service open season whereby industry committed to transporting approximately 1.5 bcf/d from Empress, Alberta to the Dawn market in Southern Ontario. Advantage's commitment to this firm transportation service was 55,600 GJ/d (52,700 mcf/d) that began November 1, 2017 and represents approximately 20% of our current production.

Doig/Montney Land Acquisitions

In 2017, Advantage acquired 37 additional sections of Doig/Montney rights in the Valhalla, Wembley and Progress areas proximal to our existing land holdings. Subsequent to year end Advantage acquired an additional 11 sections. Advantage now holds a total of 200 net sections (128,000 net acres) of Doig/Montney rights with 110 of those sections being in the Valhalla/Progress/Wembley areas that have potential for liquids-rich and multi-layer development and the remaining 90 sections at Glacier which has multi-layer liquids-rich development in the middle Montney.

Recent Developments

NGTL Transportation

As of February 2018, the Corporation has secured increasing levels of firm natural gas transportation service on TCPL's NGTL system of up to 363 mmcf/d through 2020 and retains the ability to reduce our total commitments through existing evergreen contracts. This provides Advantage with the option to consider additional physical market diversification, in addition to our Dawn exposure, while managing our cumulative long term transportation exposure. The Corporation's philosophy is to carry sufficient firm transportation contracts to meet approximately 100% of our budgeted sales gas volumes.

Anticipated Changes in the Business

As at the date hereof and other than as disclosed herein, the Corporation does not anticipate that any material change in our business will occur during the balance of the 2018 financial year.

Significant Acquisitions

The Corporation did not complete any acquisitions during the year ended December 31, 2017 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 natural 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, 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, 2017, the Corporation employed 29 full-time employees, 27 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, 2017 contained in a report of Sproule dated February 7, 2018 (the "**Sproule Report**"). The Sproule Report evaluated, as at December 31, 2017, 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, 2017 – Forecast Prices and Costs

RESERVES CATEGORY	RESERVES			
	LIGHT CRUDE OIL AND MEDIUM CRUDE OIL		CONVENTIONAL NATURAL GAS	
	Gross (Mbbbl)	Net (Mbbbl)	Gross (MMcf)	Net (MMcf)
PROVED				
Developed Producing	4.4	4.3	455,806	415,871
Developed Non-Producing	-	-	45,049	41,095
Undeveloped	-	-	1,197,147	1,078,128
TOTAL PROVED	4.4	4.3	1,698,002	1,535,094
PROBABLE	1.2	1.1	594,271	515,050
TOTAL PROVED PLUS PROBABLE	5.6	5.5	2,292,273	2,050,144

RESERVES CATEGORY	RESERVES			
	NATURAL GAS LIQUIDS		TOTAL OIL EQUIVALENT	
	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mboe)	Net (Mboe)
PROVED				
Developed Producing	4,481.9	3,654.2	80,454.0	72,970.3
Developed Non-Producing	1,017.7	829.7	8,525.9	7,678.9
Undeveloped	17,557.2	14,109.9	217,081.7	193,797.9
TOTAL PROVED	23,056.8	18,593.8	306,061.6	274,447.2
PROBABLE	8,711.1	6,433.5	107,757.3	92,276.3
TOTAL PROVED PLUS PROBABLE	31,767.9	25,027.2	413,818.9	366,723.4

Summary of Net Present Values of Future Net Revenue of Oil and Gas Reserves as at December 31, 2017 – Forecast Prices and Costs⁽¹⁾⁽²⁾⁽³⁾

RESERVES CATEGORY	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⁾ (\$/boe)	
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%		
	(\$000's)	(\$000's)	(\$000's)	(\$000's)	(\$000's)	(\$000's)	(\$000's)	(\$000's)	(\$000's)	(\$000's)		
PROVED												
Developed Producing	1,291,370	1,027,278	835,646	705,904	613,906	1,243,902	1,006,858	826,242	701,323	611,568	11.45	
Developed Non-Producing	172,031	118,755	91,582	75,218	64,255	126,940	94,427	77,713	66,980	59,201	11.93	
Undeveloped	3,110,192	1,563,430	842,153	464,582	248,778	2,261,474	1,113,751	575,117	293,239	132,688	4.35	
TOTAL PROVED	4,573,594	2,709,463	1,769,381	1,245,703	926,938	3,632,316	2,215,036	1,479,071	1,061,543	803,458	6.45	
PROBABLE	2,297,267	1,237,088	780,609	543,675	403,957	1,679,360	905,167	573,246	401,779	301,063	8.46	
TOTAL PROVED PLUS PROBABLE	6,870,860	3,946,551	2,549,991	1,789,379	1,330,895	5,311,676	3,120,203	2,052,317	1,463,322	1,104,521	6.95	

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, 2017 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, 2017.

Total Future Net Revenue (Undiscounted) as at December 31, 2017 – 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	9,230,942	1,047,531	1,926,627	1,520,675	162,515	4,573,594	941,278	3,632,316
Proved Plus Probable Reserves	12,852,334	1,611,591	2,539,212	1,657,081	173,590	6,870,860	1,559,185	5,311,676

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, 2017 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, 2017.

Future Net Revenue by Product Type as at December 31, 2017 – 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⁾	173	13.91
Natural Gas Liquids	-	-
Conventional Natural Gas ⁽²⁾	1,769,208	6.45
Total Proved	1,769,381	
Proved plus Probable reserves		
Light Crude Oil and Medium Crude Oil ⁽¹⁾	214	13.46
Natural Gas Liquids	-	-
Conventional Natural Gas ⁽²⁾	2,549,777	6.95
Total Proved Plus Probable reserves	2,549,991	

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, 2017, 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 Assumptions as at December 31, 2017 – Forecast Prices and Costs

Year	Western Canada Select 20.5° API (\$Cdn/bbl)	Canadian Light Sweet Crude Oil 40° 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)
	2018	51.05	65.44	2.85	67.72	48.73	0.0	0.0
2019	59.61	74.51	3.11	75.61	55.49	2.0	2.0	0.820
2020	64.94	78.24	3.65	78.82	57.65	2.0	2.0	0.850
2021	68.43	82.45	3.80	82.35	60.12	2.0	2.0	0.850
2022	69.80	84.10	3.95	84.07	61.32	2.0	2.0	0.850
2023	71.20	85.78	4.05	85.82	62.55	2.0	2.0	0.850
2024	72.62	87.49	4.15	87.61	63.80	2.0	2.0	0.850
2025	74.07	89.24	4.25	89.43	65.07	2.0	2.0	0.850
2026	75.55	91.03	4.36	91.29	66.37	2.0	2.0	0.850
2027	77.06	92.85	4.46	93.19	67.70	2.0	2.0	0.850
2028	78.61	94.71	4.57	95.12	69.06	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, 2017, were \$2.82/Mcf for conventional natural gas, \$62.73/bbl for crude oil, and \$49.04/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, 2017 against such reserves as at December 31, 2016 based on forecast prices and cost assumptions.

FACTORS	Light Crude Oil and Medium Crude Oil			Natural Gas Liquids		
	Proved (Mbbbl)	Probable (Mbbbl)	Proved Plus Probable (Mbbbl)	Proved (Mbbbl)	Probable (Mbbbl)	Proved Plus Probable (Mbbbl)
December 31, 2016	8.4	2.7	11.1	15,523.7	8,005.1	23,528.8
Extensions	-	-	-	1,274.3	713.2	1,987.5
Improved Recovery	-	-	-	-	-	-
Infill Drilling	-	-	-	5,618.5	1,912.6	7,531.1
Technical Revisions ⁽¹⁾	(7.8)	(2.7)	(10.5)	1,075.9	(1,918.8)	(842.9)
Discoveries	-	-	-	-	-	-
Acquisitions	4.5	1.2	5.7	2.0	0.4	2.4
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	6.4	(1.4)	5.0
Production	(0.7)	-	(0.7)	(444.0)	-	(444.0)
December 31, 2017	4.4	1.2	5.6	23,056.8	8,711.1	31,767.9

FACTORS	Conventional Natural Gas			Oil Equivalent		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (MBoe)	Probable (MBoe)	Proved Plus Probable (MBoe)
December 31, 2016	1,437,149	618,249	2,055,398	255,056.9	111,049.3	366,106.2
Extensions	30,677	20,843	51,520	6,387.1	4,187.0	10,574.2
Improved Recovery	-	-	-	-	-	-
Infill Drilling	165,289	51,220	216,509	33,166.7	10,449.3	43,615.9
Technical Revisions ⁽¹⁾	148,498	(95,886)	52,612	25,817.8	(17,902.5)	7,915.3
Discoveries	-	-	-	-	-	-
Acquisitions	43	12	55	13.7	3.6	17.3
Dispositions	-	-	-	-	-	-
Economic Factors	(222)	(167)	(389)	(30.6)	(29.2)	(59.8)
Production	(83,432)	-	(83,432)	(14,350.0)	-	(14,350.0)
December 31, 2017	1,698,002	594,271	2,292,273	306,061.6	107,757.3	413,818.9

Notes:

- (1) Technical revisions accounted for 40% of the total proved reserve additions and 13% 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.

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

Year	Light Crude Oil and Medium Crude Oil (Mbbbl)		Conventional Natural Gas (MMcf)		NGLs (Mbbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2015	-	-	86,336	876,137	2,060.6	8,694.7
2016	-	-	142,211	1,027,433	3,166.1	11,281.4
2017	-	-	195,966	1,197,147	6,892.8	17,557.2

Sproule has assigned 217.1 MMboe of gross proved undeveloped reserves in the Sproule Report under forecast prices and costs, together with \$1.5 billion of associated undiscounted future capital expenditures. Proved undeveloped capital spending in the first two forecast years of the Sproule Report accounts for \$431.6 million, or 28%, of the total forecast. These figures increase to \$1.0 billion or 68%, 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

Year	Light Crude Oil and Medium Crude Oil (Mbbbl)		Conventional Natural Gas (MMcf)		NGLs (Mbbbl)	
	First	Cumulative	First	Cumulative	First	Cumulative
	Attributed	at Year End	Attributed	at Year End	Attributed	at Year End
2015	-	-	60,502	497,612	1,252.5	6,658.5
2016	-	-	32,473	481,140	800.1	6,371.5
2017	-	-	72,063	444,717	2,625.8	6,972.9

Sproule has assigned 81.1 MMboe of gross probable undeveloped reserves in the Sproule Report under forecast prices and costs, together with \$136.0 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 16%, of the total forecast. These figures increase to \$99.5 million or 73%, 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 \$14.5 million (\$173.6 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 \$49.9 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 \$5.2 million with the majority of these costs expected to be incurred between 2041 to 2077.

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.

Year	Forecast Prices and Costs	
	Proved Reserves (\$millions)	Proved Plus Probable Reserves (\$millions)
2018	177.2	183.2
2019	256.3	272.3
2020	259.4	285.7
2021	183.0	183.0
2022	152.1	203.8
Total: Undiscounted for all years	1,520.7	1,657.1

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, 2017 unless otherwise noted and reserves quoted are as reported in the Sproule Report.

Glacier Area, Alberta (Glacier/Valhalla/Wembley/Progress)

The Glacier/Valhalla/Wembley/Progress properties lie 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. Advantage now holds a total of 200 net sections (128,000 net acres) of Doig/Montney rights with 110 of those sections being in the Valhalla/Progress/Wembley areas that have potential for liquids-rich, multi-layer development and each of these three areas having at least 30 contiguous sections that can support scalable development. At Valhalla, Wembley and Progress ongoing industry drilling and production activity has demonstrated encouraging initial results with attractive liquid yields and gas rates. Industry drilling adjacent to our lands have targeted multiple Montney layers with results demonstrating liquids-rich gas accumulations in all layers to date. The remaining 90 net sections are held at Glacier where 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. During 2017, Advantage continued with our 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 28 horizontal wells and 3 vertical recompletions have tested and produced in intervals other than the Lower Doig or Lower Montney, with an additional 11 wells either cased or in various stages of completion and progressing towards being placed on production. This development has resulted in significant delineation and de-risking of the liquid rich Middle Montney resource potential at Glacier.

Based on current reserves assignments as of December 31, 2017, these properties have a combined proved plus probable reserve life index ("**RLI**") of 28 years at a production rate of 245 MMcfe/d, which was the average production rate achieved at the Glacier Area during the fourth quarter of 2017. RLI is calculated by dividing the total volume of proved plus probable reserves of 2.5 Tcfe 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 2017, Advantage has drilled and completed 185 net horizontal wells on our properties 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 service wells that support our water disposal system.

As at March 5, 2018, production is approximately 245 MMcfe/d or 40,800 boe/d with our Valhalla property producing approximately 5 MMcfe/d and Glacier producing 240 MMcfe/d. Advantage's Upper, Middle and Lower Montney wells are continuing to demonstrate strong production performance.

Throughout 2017 Advantage drilled 33.4 net Montney horizontal wells across all our properties which included delineation drilling on our undeveloped land holdings at Valhalla, Wembley and Progress. During the year ended December 31, 2017, Advantage drilled 28.0, 3.4, 1.0 and 1.0 net wells at Glacier, Valhalla, Wembley and Progress respectively. At Glacier, Advantage drilled 28 net wells focusing our drilling on multi-well pads with our smallest pad drilled during the year being 8 wells.

Advantage's current standing well inventory consists of 31 total wells of which 8 wells are tied-in waiting to be produced, 10 wells are in various stages of completion, and 13 wells are cased waiting to be completed. These wells are estimated to provide sufficient productive capacity to attain our 2018 annual production target.

Advantage owns and operates a 100% working interest gas plant located at 05-02-76-12W6. The plant currently has 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. Construction of the expansion has significantly progressed and all major equipment is in place with the majority of the mechanical and electrical work completed. Commissioning of the new equipment along with a shut down for final tie-in of the new equipment will occur in April 2018.

Advantage's strategy of owning and operating our own infrastructure has helped us achieve an industry leading low cost structure.

Gas is sold through Advantage's sales pipeline system into the TransCanada Pipelines Limited Alberta system. In Q4 of 2018 Advantage will also be connected to the Alliance pipeline system via the installation of a new meter station. The operating cost structure of the Corporation is very favorable with combined field and plant operating costs averaging \$0.25/Mcfe in 2017.

Oil and Gas Wells

The following table sets forth the number and status of wells as at December 31, 2017 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	-	-	-	-	182	172	53	49

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, 2017.

	Gross Acres	Net Acres
Alberta, Canada	71,040	71,040

We expect that rights to explore, develop and exploit 5 sections (3,200 net acres) of our undeveloped land holdings will expire by December 31, 2018. The land expirations do not consider our 2018 exploitation and development program that may result in extending or eliminating such potential expirations. We closely monitor land expirations as compared to our development program 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 period of three years and 50% over the fourth and fifth years. In addition, Advantage is able to enter into basis swap arrangements to any natural gas price point in North America for up to 100,000 MMBtu/day with a maximum term of seven years. Basis swap arrangements do not count against the limitations on hedged production. 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	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
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

⁽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.

Natural gas – AECO/Henry Hub Basis Differential

Basis swap	January 2018 to December 2019	25,000 mcf/d	Henry Hub less US \$0.95/mcf
Basis swap	January 2019 to December 2019	25,000 mcf/d	Henry Hub less US \$0.90/mcf

Natural gas – Dawn

Fixed price swap	December 2017 to March 2018	10,000 mcf/d	US \$3.45/mcf
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Subsequent to December 31, 2017, the Corporation entered into the following derivative contracts:

Natural gas – AECO/Henry Hub Basis Differential

Basis swap	January 2021 to December 2024	5,000 mcf/d	Henry Hub less US \$1.135/mcf
Basis swap	January 2021 to December 2024	2,500 mcf/d	Henry Hub less US \$1.185/mcf
Basis swap	January 2021 to December 2024	17,500 mcf/d	Henry Hub less US \$1.20/mcf
Basis swap	January 2020 to December 2020	5,000 mcf/d	Henry Hub less US \$1.20/mcf
Basis swap	January 2020 to December 2024	15,000 mcf/d	Henry Hub less US \$1.20/mcf

Tax Horizon

In 2017, 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, 2017:

Capital Expenditures (\$ thousands)	2017
Drilling, completions and workovers	143,797
Well equipping and facilities	97,652
Other	118
Expenditures on property, plant and equipment	241,567
Property Acquisition – Proved Properties	-
Property Acquisition – Unproved Properties	7,207
Property dispositions	-
Exploration costs	-
Development costs	-
Total capital expenditures	248,774

Exploration and Development Activities

The following table sets forth the gross and net wells in which we participated during the year ended December 31, 2017:

	Exploratory		Development		Total	
	Gross	Net	Gross	Net	Gross	Net
Oil wells	-	-	-	-	-	-
Gas wells	2.0	2.0	32.0	31.4	34.0	33.4
Service wells	-	-	-	-	-	-
Stratigraphic test wells	-	-	-	-	-	-
Dry holes	-	-	-	-	-	-
Total	2.0	2.0	32.0	31.4	34.0	33.4

Subject to, among other things, the availability of drilling rigs and weather that permits access to drill sites, in the first 6 months of 2018, we plan to drill 2 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, 2018 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		Conventional Natural Gas		Natural Gas Liquids		Total	
	(bbls/d)		(Mcf/d)		(bbls/d)		(Boe/d)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved Producing	1	1	198,871	187,304	1,896	1,756	35,043	32,974
Proved Developed Non- Producing	-	-	14,323	13,600	414	393	2,801	2,659
Proved Undeveloped	-	-	16,964	16,115	167	159	2,995	2,844
Total Proved	1	1	230,159	217,019	2,478	2,307	40,839	38,478
Total Probable	-	-	20,485	19,449	367	346	3,781	3,588
Total Proved Plus Probable	1	1	250,644	236,468	2,844	2,653	44,619	42,066

The following table indicates our production estimated from our important fields for the year ended December 31, 2018:

	Light Crude Oil and Medium Crude Oil		Conventional Natural Gas		Natural Gas Liquids		Total	
	(bbls/d)		(Mcf/d)		(bbls/d)		(Boe/d)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta – Glacier Property	-	-	238,059	224,581	2,312	2,151	41,988	39,581

Production History

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

	Quarter Ended 2017				Year Ended
	Mar. 31	June 30	Sept. 30	Dec. 31	Dec. 31, 2017
Average Daily Production ⁽¹⁾					
Light Crude Oil and Medium Crude Oil (bbls/d)	446	507	516	402	468
NGLs (bbls/d)	705	591	879	825	750
Conventional Natural Gas (mcf/d)	230,906	225,844	219,812	237,780	228,583
Combined (mcf/d)	237,812	232,432	228,182	245,142	235,891
Average Prices Received ⁽³⁾					
Light Crude Oil and Medium Crude Oil (\$/bbl)	60.74	65.39	56.60	69.60	62.73
NGLs (\$/bbl)	49.30	50.32	41.28	56.03	49.04
Conventional Natural Gas (\$/Mcf)	2.99	2.98	1.84	2.15	2.49
Combined (\$/Mcf)	3.17	3.16	2.06	2.38	2.69
Royalties Paid					
Light Crude Oil and Medium Crude Oil (\$/bbl)	2.67	3.47	(0.55)	2.14	1.88
NGLs (\$/bbl)	4.85	8.53	(0.93)	2.98	3.35
Conventional Natural Gas (\$/Mcf)	0.08	0.13	(0.02)	0.06	0.06
Combined (\$/Mcf)	0.10	0.15	(0.02)	0.07	0.07
Production Costs ^{(4) (5)}					
Light Crude Oil and Medium Crude Oil (\$/bbl)	1.37	1.60	1.52	1.60	1.52
NGLs (\$/bbl)	1.36	1.60	1.51	1.58	1.52
Conventional Natural Gas (\$/Mcf)	0.23	0.27	0.25	0.26	0.25
Combined (\$/Mcf)	0.23	0.27	0.25	0.26	0.25
Transportation Costs					
Light Crude Oil and Medium Crude Oil (\$/bbl)	6.80	10.84	7.23	9.17	8.43
NGLs (\$/bbl)	6.81	10.82	7.21	9.16	8.43
Conventional Natural Gas (\$/Mcf)	0.36	0.33	0.31	0.47	0.37
Combined (\$/Mcf)	0.38	0.37	0.35	0.50	0.40
Netback Received ^{(2) (6)}					
Light Crude Oil and Medium Crude Oil (\$/bbl)	49.90	49.48	48.40	56.69	50.90
NGLs (\$/bbl)	36.28	29.37	33.49	42.31	35.74
Conventional Natural Gas (\$/Mcf)	2.32	2.25	1.30	1.36	1.81
Combined (\$/Mcf)	2.46	2.37	1.48	1.55	1.97

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) The Corporation does 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, 2017:

	Light Crude Oil and Medium Crude Oil	Conventional Natural Gas	Natural Gas Liquids	Total
	<u>(bbls/d)</u>	<u>(Mcf/d)</u>	<u>(bbls/d)</u>	<u>(Mcf/d)</u>
Alberta – Glacier Property	-	224,590	1,132	231,384

Marketing

Our natural gas and NGL production is primarily sold through marketing companies at current market prices. Risk management price hedging is done outside of our marketing contracts. Natural gas marketing 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, NGL and natural gas production. Oil, NGL 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, NGL 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

Advantage is pro-active in its approach to environmental concerns. Procedures are in place to ensure that significant care is taken in the day-to-day management of its 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 seven years, achieving first-quartile results in each year. The COR Health and Safety Auditing and the COR Safety Program require commitment to continuous improvement in environment, health and safety management practices, including sound planning and implementation. The program is externally audited every 3 years and

internally audited 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 operates in compliance with all applicable regulations and ensures all staff and contractors employ sound practices to protect the environment and to ensure employee and public health and safety.

In 2017, the Corporation participated in multiple Enhanced Production Audits, all of which it passed. Advantage's incident ratings in 2017 were significantly below industry averages. In addition, a total of 26 reclamation certificates were received by Advantage in 2017. Advantage's spill volumes in 2017 were zero and in the last five years, only one year had a very minor spill, which was negligible.

The Corporation maintains and will continue to maintain a safe and environmentally responsible work place, and will continue to 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, with previous roles including 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.

Name, Province and Country of Residence	Position Held and Period Served as a Director or Officer ⁽⁴⁾⁽⁵⁾	Principal Occupations During Past Five Years
Stephen E. Balog ⁽¹⁾⁽²⁾⁽³⁾ Alberta, Canada	Director since August 16, 2007	President, West Butte Management Inc., a private consulting company that provides business and technical 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. Mr. Balog 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 B. 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 G. 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. Mr. Haggis 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. Mr. Haggis was also Chair of the Audit Committee of C.A. Bancorp and Prime Restaurants Royalty Income Fund and the Chair of Canadian Pacific Railway. Mr. Haggis was on the Board of UBC Investment Management Inc. Currently, Mr. Haggis is the Chairman of Alberta Enterprise Corp a Director of Home Capital Group Inc. 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. Director of Chinook Energy Inc. since November 2014 and Director of Tourmaline Oil Corp. since November 2015. 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).
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	Mr. Reid is a partner at the Calgary based law firm of Burnet, Duckworth & Palmer LLP and has practiced corporate and securities law since 1990. Mr. Reid 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 5, 2018, the directors and executive officers of Advantage, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 2,495,651 Common Shares, or approximately 1.3% 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 5, 2018, 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, 2017, 2016, and 2015, 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, 2017, there were 185,963,186 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.

<u>Period</u>	<u>High</u>	<u>Low</u>	<u>Volume</u>
	(\$)	(\$)	
TSX Trading			
<u>2017</u>			
January	9.31	8.22	12,769,130
February	8.83	7.86	10,056,301
March	8.84	7.65	15,562,000
April	9.29	8.24	11,099,100
May	9.18	8.00	12,532,400
June	8.82	8.02	11,484,400
July	9.24	8.37	9,687,000
August	8.64	7.78	10,560,700
September	8.24	7.48	10,740,900
October	7.81	6.57	11,524,700
November	7.44	5.98	13,266,000
December	6.19	4.84	25,650,800
<u>2018</u>			
January	5.73	3.90	38,400,100
February	4.26	3.48	23,628,500
NYSE Trading (U.S.\$)			
<u>2017</u>			
January	6.90	6.20	2,210,186
February	6.70	6.00	1,817,630
March	6.68	5.70	2,907,400
April	6.94	6.03	1,288,700
May	6.80	5.82	2,905,600
June	6.80	5.95	1,824,700
July	7.35	6.48	2,367,600
August	6.90	6.20	1,653,100
September	6.70	6.13	1,302,900
October	6.25	5.05	2,564,300

Period	High	Low	Volume
	(\$)	(\$)	
November	5.90	4.63	2,542,800
December	4.90	3.75	6,501,100
<u>2018</u>			
January	4.58	3.15	7,851,400
February	3.45	2.75	6,610,500

Prior Sales

During the year ended December 31, 2017, the Corporation did not grant any stock options pursuant to the Corporation's stock option plan and granted 723,676 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, 2017, 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, 2017 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, 2017 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 external 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. The Corporation's independent auditors are PricewaterhouseCoopers LLP, Chartered Professional Accountants, who have issued an independent auditor's report dated March 5, 2018 in respect of the Corporation's consolidated financial statements as at December 31, 2017 and December 31, 2016 and for each of the years ended December 31, 2017 and the Corporation's internal control over financial reporting as at December 31, 2017. PricewaterhouseCoopers LLP has advised that they are independent with respect to the Corporation within the meaning of the Rules of Professional Conduct with Guidance of the Chartered Professional Accountants of Alberta and the rules of the US Securities and Exchange Commission.

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.

<u>Name, Province and Country of Residence</u>	<u>Independent</u>	<u>Financially Literate</u>	<u>Relevant Education and Experience</u>
Paul G. 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. Haggis has extensive financial markets and public board experience having served on the Board of Directors of Canadian Tire Bank until March 30, 2012. Mr. Haggis 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. Mr. Haggis was also Chair of the Audit Committee of C.A. Bancorp and Prime Restaurants Royalty Income Fund and the Chair of Canadian Pacific Railway. Mr. Haggis was on the Board of UBC Investment Management Inc. Currently, Mr. Haggis is the Chairman of Alberta Enterprise Corp a Director of Home Capital Group Inc. 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 E. Balog Alberta, Canada	Yes	Yes	President, West Butte Management Inc., a private consulting company that provides business and technical 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. Mr. Balog was a key contributor to the development and use of

<u>Name, Province and Country of Residence</u>	<u>Independent</u>	<u>Financially Literate</u>	<u>Relevant Education and Experience</u>
Jill T. Angevine Alberta, Canada	Yes	Yes	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. Vice President and Portfolio Manager at Matco Financial Inc. (an independent, privately held asset management firm) since October 2013. Director of Chinook Energy Inc. since November 2014 and Director of Tourmaline Oil Corp. since November 2015. 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	2017	2016
Audit Fees ⁽¹⁾	\$268,000	\$263,000
Audit-Related Fees ⁽²⁾	45,000	45,000
Tax Fees ⁽³⁾	8,000	16,500
Other Fees ⁽⁴⁾	-	39,900
Total	\$321,000	\$364,400

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 carrying on business in the crude oil and natural gas sector in Canada are subject to extensive controls and regulations imposed through legislation of the federal government and the provincial governments where the companies have assets or operations. While these regulations do not affect the Corporation's operations in any manner that is materially different than they affect other similarly-sized industry participants with similar assets and operations, investors should consider such regulations carefully. Although governmental legislation is a matter of public record, the Corporation is unable to predict what additional legislation or amendments governments may enact in the future.

The Corporation holds interests in crude oil and natural gas properties, along with related assets, primarily in the Canadian province of Alberta. The Corporation's assets and operations are regulated by administrative agencies deriving authority from underlying legislation. Regulated aspects of the Corporation's upstream crude oil and natural gas business include all manner of activities associated with the exploration for and production of crude oil and natural gas, including, among other matters: (i) permits for the drilling of wells; (ii) technical drilling and well requirements; (iii) permitted locations and access of operation sites; (iv) operating standards regarding conservation of produced substances and avoidance of waste, such as restricting flaring and venting; (v) minimizing environmental impacts; (vi) storage, injection and disposal of substances associated with production operations; and (vii) the abandonment and reclamation of impacted sites. In order to conduct crude oil and natural gas operations and remain in good standing with the applicable provincial regulatory scheme, 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 in this regard can be costly and a breach of the same may result in fines or other sanctions. The discussion below outlines certain pertinent conditions and regulations that impact the crude oil and natural gas industry in Western Canada.

Pricing and Marketing in Canada

Crude Oil

Producers of crude oil are entitled to negotiate sales contracts directly with crude oil purchasers, which results in the market determining the price of crude oil. Worldwide supply and demand factors primarily determine crude oil prices; however, regional market and transportation issues also influence prices. The specific price depends, in part, on crude

oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, supply/demand balance and contractual terms of sale.

Natural Gas

The price of natural gas sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. The price received by a natural gas producer depends, in part, on the price of competing natural gas supplies and other fuels, natural gas quality, distance to market, availability of transportation, length of contract term, weather conditions, supply/demand balance and other contractual terms. Spot and future prices can also be influenced by supply and demand fundamentals on various trading platforms.

Natural Gas Liquids

The price of condensate and other NGLs such as ethane, butane and propane sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such price depends, in part, on the quality of the NGLs, price of competing chemical stock, distance to market, access to downstream transportation, length of contract term, supply/demand balance and other contractual terms.

Exports from Canada

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

Orders from the NEB provide a short-term alternative to export licences and may be issued more expediently, since they do not require a public hearing or approval from the cabinet of the Canadian federal government. Orders are issued pursuant to the Part VI Regulation for up to one or two years depending on the substance, with the exception of natural gas (other than NGLs) for which an order may be issued for up to twenty years for quantities not exceeding 30,000 m³ per day.

As to price, 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 federal government.

Currently, the Corporation does not directly enter into contracts to export its production outside of Canada.

As discussed in more detail below, one major constraint to the export of crude oil, natural gas and NGLs outside of Canada is the deficit of overall pipeline and other transportation capacity to transport production from Western Canada to the United States and other international markets. Although certain pipeline or other transportation projects are underway, many contemplated projects have been cancelled or are delayed due to regulatory hurdles, court challenges and economic and political factors. The transportation capacity deficit is not likely to be resolved quickly given the significant length of time required to complete major pipeline or other transportation projects once all regulatory and other hurdles have been cleared. In addition, production of crude oil, natural gas and NGLs in Canada is expected to continue to increase, which may further exacerbate the transportation capacity deficit.

Transportation Constraints and Market Access

Producers negotiate with pipeline operators (or other transport providers) to transport their products, which may be done on a firm or interruptible basis. Due to growing production and a lack of new and expanded pipeline and rail

infrastructure capacity, producers in Western Canada have experienced low pricing relative to other markets in the last several years. Transportation availability is highly variable across different areas and regions, which can determine the nature of transportation commitments available, the numbers of potential customers that can be reached in a cost-effective manner and the price received.

Developing a strong network of transportation infrastructure for crude oil, natural gas and NGLs, including by means of pipelines, rail, marine and trucks, in order to obtain better access to domestic and international markets has been a significant challenge to the Canadian crude oil and natural gas industry. Improved means of access to global markets, especially the Midwest United States and export shipping terminals on the west coast of Canada, would help to alleviate the pressures of pricing discussed. Several proposals have been announced to increase pipeline capacity out of Western Canada, to reach Eastern Canada, the United States and international markets via export shipping terminals on the west coast of Canada. While certain projects are proceeding, the regulatory approval process as well as economic and political factors for transportation and other export infrastructure has led to the delay of many pipeline projects or their cancellation altogether.

Under the Canadian constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and require approval by both the NEB and the cabinet of the federal government. However, recent years have seen a perceived lack of policy and regulatory certainty at a federal level. Although the current federal government recently introduced draft legislation to amend the current federal approval processes, it is uncertain when the new legislation will be brought into force and whether any changes to the draft legislation will be made before the legislation is brought into force. It is also uncertain whether any new approval process adopted by the federal government will result in a more efficient approval process. The lack of regulatory certainty is likely to have an influence on investment decisions for major projects. Even when projects are approved on a federal level, such projects often face further delays due to interference by provincial and municipal governments as well as court challenges on various issues such as indigenous title, the government's duty to consult and accommodate indigenous peoples and the sufficiency of environmental review processes, which creates further uncertainty. Export pipelines from Canada to the United States face additional uncertainty as such pipelines require approvals of several levels of government in the United States.

Natural gas prices in Alberta and British Columbia have also been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. While companies that secure firm access to transport their natural gas production out of Western Canada may be able to access more markets and obtain better pricing, other companies may be forced to accept spot pricing in Western Canada for their natural gas, which in the last several years has generally been depressed (at times producers have received negative pricing for their natural gas production). Required repairs or upgrades to existing pipeline systems have also led to further reduced capacity and apportionment of firm access, which in Western Canada may be further exacerbated by natural gas storage limitations. Additionally, while a number of liquefied natural gas export plants have been proposed for the west coast of Canada, government decision-making, regulatory uncertainty, opposition from environmental and indigenous groups, and changing market conditions, have resulted in the cancellation or delay of many of these projects.

The North American Free Trade Agreement and Other Trade Agreements

The North American Free Trade Agreement ("NAFTA") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. Under the terms of NAFTA, Canada remains 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 Canada 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. Further, all three signatory countries are prohibited from imposing a minimum or maximum price requirement on exports (where any other form of quantitative restriction is prohibited) and imports (except as permitted in the enforcement of countervailing and anti-dumping orders and undertakings). NAFTA also requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of such changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements.

In 2017, the United States government announced its intention to renegotiate NAFTA. As a result, Canada, the United States and Mexico began renegotiating the terms of NAFTA in mid-2017. The United States has also suggested that it might give notice of the termination of NAFTA if it is not satisfied with the outcome of the renegotiations. If the United States does give notice of its intent to terminate or withdraw from NAFTA, the earliest such termination or withdrawal could occur would be six months after such notice is given. The renegotiations are still underway and the outcome of such negotiations remain unclear, but as the United States remains by far Canada's largest trade partner and the largest international market for the export of crude oil, natural gas and NGLs from Canada, any changes to, or termination of, NAFTA could have an impact on Western Canada's crude oil and natural gas industry at large, including the Corporation's business.

Canada has also pursued a number of other international free trade agreements with other countries around the world. As a result, a number of free trade or similar agreements are in force between Canada and certain other countries while in other circumstances Canada has been unsuccessful in its efforts. Canada and the European Union recently agreed to the Comprehensive Economic and Trade Agreement ("**CETA**"), which provides for duty-free, quota-free market access for Canadian oil and gas products to the European Union. Although CETA remains subject to ratification by certain national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017. In addition, Canada and ten other countries recently concluded discussions and agreed on the draft text of the Comprehensive and Progressive Agreement for Trans-Pacific Partnership ("**CPTPP**"), which is intended to allow for preferential market access among the countries that are parties to the CPTPP. The text of CPTPP has not been finalized or published and the agreement remains subject to ratification by the governments of each of the countries involved. While it is uncertain what effect CETA, CPTPP or any other trade agreements will have on the oil and gas industry in Canada, the lack of available infrastructure for the offshore export of oil and gas may limit the ability of Canadian oil and gas producers to benefit from such trade agreements.

Land Tenure

The respective provincial governments (i.e. the Crown), predominantly own the mineral rights to crude oil and natural gas located in Western Canada, with the exception of Manitoba (which only owns 20% of the mineral rights). Provincial governments grant rights to explore for and produce crude 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. The provincial governments in Western Canada's provinces conduct regular land sales where crude oil and natural gas companies bid for leases to explore for and produce crude oil and natural gas pursuant to mineral rights owned by the respective provincial governments. The leases generally have a fixed term; however, a lease may generally be continued after the initial term where certain minimum thresholds of production have been reached, all lease rental payments have been paid on time and other conditions are satisfied.

To develop crude oil and natural gas resources, it is necessary for the mineral estate owner to have access to the surface lands as well. Each province has developed its own process for obtaining surface access to conduct operations that operators must follow throughout the lifespan of a well, including notification requirements and providing compensation for affected persons for lost land use and surface damage.

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. Additionally, Alberta has shallow rights reversion for shallow, non-productive geological formations for new leases and licences.

In addition to Crown ownership of the rights to crude oil and natural gas, private ownership of crude oil and natural gas (i.e. freehold mineral lands) also exists in the province of Alberta. According to Alberta Energy, approximately 19% of mineral rights in the Province of Alberta are owned by private freehold owners and other non-Crown entities. Rights to explore for and produce such crude oil and natural gas are granted by a lease or other contract on such terms and conditions as may be negotiated between the owner of such mineral rights and crude oil and natural gas explorers and producers.

An additional category of mineral rights ownership includes ownership by the Canadian federal government of some legacy mineral lands and within indigenous reservations designated under the *Indian Act* (Canada). Indian Oil and Gas Canada ("**IOGC**"), which is a federal government agency, manages subsurface and surface leases, in consultation

with the applicable indigenous peoples, for exploration and production of crude oil and natural gas on indigenous reservations.

Royalties and Incentives

General

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 crude oil, natural gas and NGLs 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 substance produced.

Occasionally the governments of Western Canada's provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are often introduced when commodity prices are low to encourage exploration and development activity. In addition, such programs may be introduced to encourage producers to undertake initiatives using new technologies that may enhance or improve recovery of crude oil, natural gas and NGLs.

Producers and working interest owners of crude oil and natural gas rights may also carve out additional royalties or royalty-like interests through non-public transactions, which include the creation of instruments such as overriding royalties, net profits interests and net carried interests.

Alberta

In Alberta, the provincial government royalty rates apply to Crown-owned mineral rights. In 2016, Alberta adopted a modernized Alberta royalty framework (the "**Modernized Framework**") that applies to all wells drilled after January 1, 2017. The previous royalty framework (the "**Old Framework**") will continue to apply to wells drilled prior to January 1, 2017 for a period of ten years ending on December 31, 2026. After the expiry of this ten-year period, these older wells will become subject to the Modernized Framework.

The Modernized Framework applies to all hydrocarbons other than oil sands which will remain subject to their existing royalty regime. Royalties on production from non-oil sands wells under the Modernized Framework are determined on a "revenue-minus-costs" basis with the cost component based on a Drilling and Completion Cost Allowance formula for each well, depending on its vertical depth and/or horizontal length. The formula is based on the industry's average drilling and completion costs as determined by the Alberta Energy Regulator (the "**AER**") on an annual basis.

Producers pay a flat royalty rate of 5% of gross revenue from each well that is subject to the Modernized Framework until the well reaches payout. Payout for a well is the point at which cumulative gross revenues from the well equals the Drilling and Completion Cost Allowance for the well set by the AER. After payout, producers pay an increased post-payout royalty on revenues of between 5% and 40% determined by reference to the then current commodity prices of the various hydrocarbons. Similar to the Old Framework, the post-payout royalty rate under the Modernized Framework varies with commodity prices. Once production in a mature well drops below a threshold level where the rate of production is too low to sustain the full royalty burden, its royalty rate is adjusted downward towards a minimum of 5% as the mature well's production declines. As the Modernized Framework uses deemed drilling and completion costs in calculating the royalty and not the actual drilling and completion costs incurred by a producer, low cost producers benefit if their well costs are lower than the Drilling and Completion Cost Allowance and, accordingly, they continue to pay the lower 5% royalty rate for a period of time after their wells achieve actual payout.

The Old Framework is applicable to all conventional crude oil and natural gas wells drilled prior to January 1, 2017 and bitumen production. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for conventional crude oil production under the Old Framework range from a base rate of 0% to a cap of

40%. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for natural gas production under the Old Framework range from a base rate of 5% to a cap of 36%. The Old Framework also includes a natural gas royalty formula which provides for a reduction based on the measured depth of the well below 2,000 metres deep, as well as the acid gas content of the produced gas. Under the Old Framework, the royalty rate applicable to NGLs is a flat rate of 40% for pentanes and 30% for butanes and propane. Currently, producers of crude oil and natural gas from Crown lands in Alberta are also required to pay annual rental payments, at a rate of \$3.50 per hectare, and make monthly royalty payments in respect of crude oil and natural gas produced.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage crude oil and natural gas development and new drilling. In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources, including as applied to coalbed methane wells, shale gas wells and horizontal crude oil and natural gas wells.

Freehold mineral taxes are levied for production from freehold mineral lands on an annual basis on calendar year production. Freehold mineral taxes are calculated 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. On average, in Alberta the tax levied is 4% of revenues reported from freehold mineral title properties. The freehold mineral taxes would be in addition to any royalty or other payment paid to the owner of such freehold mineral rights, which are established through private negotiation.

Freehold and Other Types of Non-Crown Royalties

Royalties on production from privately-owned freehold lands are negotiated between the mineral freehold owner and the lessee under a negotiated lease or other contract.

In addition to the royalties payable to the mineral owners, producers of crude oil and natural gas from freehold lands in each of the Western Canadian provinces are required to pay freehold mineral taxes or production taxes. Freehold mineral taxes or production taxes are taxes levied by a provincial government on crude oil and natural gas production from lands where the Crown does not hold the mineral rights. A description of the freehold mineral taxes payable in Alberta is included in the above description of the royalty regimes in Alberta.

IOGC is a special agency responsible for managing and regulating the crude oil and natural gas resources located on indigenous reservations across Canada. IOGC's responsibilities include negotiating and issuing the crude oil and natural gas agreements between indigenous groups and crude oil and natural gas companies, as well as collecting royalty revenues on behalf of indigenous groups and depositing the revenues in their trust accounts. While certain standards exist, the exact terms and conditions of each crude oil and natural gas lease dictate the calculation of royalties owed, which may vary depending on the involvement of the specific indigenous group. Ultimately, the relevant indigenous group must approve the terms.

Regulatory Authorities and Environmental Regulation

General

The crude 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 are subject to governmental review and revision from time to time. Such regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain crude oil and natural 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 regulations 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 crude oil and natural gas industry.

Federal

Canadian environmental regulation is the responsibility of both the federal 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 including interprovincial pipelines.

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

On May 12, 2017, the federal government introduced the *Oil Tanker Moratorium Act* in Parliament. This legislation is aimed at providing coastal protection in northern British Columbia by prohibiting crude oil tankers carrying more than 12,500 metric tonnes of crude oil or persistent crude oil products from stopping, loading, or unloading crude oil in that area. Parliament is still considering the bill, which passed second reading on October 4, 2017. If implemented, the legislation may prevent the building of pipelines to, and export terminals located on, the portion of the British Columbia coast subject to the moratorium and, as a result, negatively affect the ability of producers to access global markets.

Alberta

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

The Government of Alberta relies on regional planning to accomplish its responsible resource development goals. Its approach to natural resource management provides for engagement and consultation with stakeholders and the public and examines the cumulative impacts of development on the environment and communities by incorporating the management of all resources, including energy, minerals, land, air, water and biodiversity. While the AER is the primary regulator for energy development, several other governmental departments and agencies may be involved in

land use issues, including Alberta Environment and Parks, Alberta Energy, the Policy Management Office, the Aboriginal Consultation Office and the Land Use Secretariat.

The Government of Alberta's land-use policy for surface land in Alberta sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of seven region-specific land-use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans. As a result, several regional plans have been implemented and others are in the process of being implemented. These regional plans may affect further development and operations in such regions.

Liability Management Rating Program

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 crude oil and natural gas wells, facilities and pipelines. Alberta's *Oil and Gas Conservation Act* (the "**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 insolvent 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 assets to deemed liabilities is assessed once each month and where a security deposit is deemed to be required, the failure to post any required amounts 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 on its public website.

In *Redwater Energy Corporation (Re)* ("**Redwater**"), the Court of Queen's Bench of Alberta found that there was an operational conflict between the abandonment and reclamation provisions of the OGCA, including the AB LLR Program, and the *Bankruptcy and Insolvency Act* (the "**BIA**"). This ruling meant that receivers and trustees have the right to renounce assets within insolvency proceedings, which was affirmed by a majority of the Alberta Court of Appeal. 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. Effectively, this means that abandonment costs will be borne by the industry-funded Orphan Well Fund or the province in these instances because any financial resources of the insolvent licensee will first be used to satisfy secured creditors under the BIA. This decision is currently under appeal to the Supreme Court of Canada, with final resolution expected in 2018.

In response to Redwater, the AER issued several bulletins and interim rule changes to govern while the case is appealed and to allow the Government of Alberta to develop appropriate regulatory measures to adequately address environmental liabilities. The AER's *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals*, which deals with licence eligibility to operate wells and facilities, was amended and now requires extensive corporate governance and shareholder information, with a particular focus on any previous companies of directors and officers that have been subject to insolvency proceedings in the last five years. All transfers of well, facility and pipeline licences in the province are subject to AER approval. As a condition of transferring existing AER licences, approvals and permits, all are assessed on a non-routine basis and the AER now requires 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, or to otherwise prove that it can satisfy its abandonment and reclamation obligations. The AER may make further rule changes in response to Redwater at any time, especially as the case heads towards a final determination, which means that additional obligations and/or different requirements may be forthcoming.

The AER has also implemented the Inactive Well Compliance Program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under *Directive*

013: Suspension Requirements for Wells ("Directive 013"). The IWCP applies to all inactive wells that are noncompliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within five years. As of April 1, 2015, each licensee is required to bring 20% of its inactive wells into compliance every year, either by reactivating or by suspending the wells in accordance with Directive 013 or by abandoning them in accordance with *Directive 020: Well Abandonment*. The list of current wells subject to the IWCP is available on the AER's Digital Data Submission system. The AER has announced that from April 1, 2015 to April 1, 2016, the number of noncompliant wells subject to the IWCP fell from 25,792 to 17,470, with 76% of licensees operating in the province having met their annual quota. The IWCP completed its second year on March 31, 2017. Overall, the AER has announced that licensees brought 19% of non-compliant wells in the IWCP into compliance with AER requirements in the second year of the IWCP.

Climate Change Regulation

Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulatory environment of the crude oil and natural gas industry in Canada.

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

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "UNFCCC") since 1992. Since its inception, the UNFCCC has instigated numerous policy experiments with respect to climate governance. On April 22, 2016, 197 countries signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. As of February 1, 2018, 174 of the 197 parties to the convention have ratified the Paris Agreement.

Following the Paris Agreement and its ratification in Canada, the Government of Canada pledged to cut its emissions by 30% from 2005 levels by 2030. Further, on December 9, 2016, the Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change (the "**Framework**"). The Framework provided for a carbon-pricing strategy, with a carbon tax starting at \$10/tonne, increasing annually until it reaches \$50/tonne in 2022. A draft legislative proposal for the federal carbon pricing system was released on January 15, 2018. This system would apply in provinces and territories that request it and in those that do not have a carbon pricing system in place that meets the federal standards in 2018. Four provinces currently have carbon pricing systems in place that would meet federal requirements (Alberta, British Columbia, Ontario and Quebec). The federal government will accept comments on the draft legislative proposals to implement the federal carbon pricing system until February 12, 2018.

On May 27, 2017, the federal government published draft regulations to reduce emissions of methane from the crude oil and natural gas sector. The proposed regulations aim to reduce unintentional leaks and intentional venting of methane, as well as ensuring that crude oil and natural gas operations use low-emission equipment and processes, by introducing new control measures. Among other things, the proposed regulations limit how much methane upstream oil and gas facilities are permitted to vent. These facilities would need to capture the gas and either re-use it, re-inject it, send it to a sales pipeline, or route it to a flare. In addition, in provinces other than Alberta and British Columbia (which already regulate such activities), well completions by hydraulic fracturing would be required to conserve or destroy gas instead of venting. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

Alberta

On November 22, 2015, the Government of Alberta introduced its Climate Leadership Plan (the "**CLP**"). The CLP has four areas of focus: implementing a carbon price on GHG emissions, phasing out coal-generated electricity and developing renewable energy, legislating an oil sands emission limit, and introducing a new methane emissions reduction plan. The Government of Alberta has since introduced new legislation to give effect to these initiatives. The

Climate Leadership Act came into force on January 1, 2017 and enabled a carbon levy that increased from \$20 to \$30 per tonne on January 1, 2018. The levy is anticipated to increase again in 2021 in line with the federal legislation. On December 14, 2016, the *Oil Sands Emissions Limit Act* came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, excluding some attributable to upgraders, the electric energy portion of cogeneration and other prescribed emissions.

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

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

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

Accountability and Transparency

In 2015, the federal government's *Extractive Sector Transparency Measures Act* (the "**ESTMA**") came into effect, which imposed mandatory reporting requirements on certain entities engaged in the "commercial development of oil, gas or minerals", including exploration, extraction and holding permits. All companies subject to ESTMA must report payments over CAD\$100,000 made to any level of a Canadian or foreign government (including indigenous groups), including royalty payments, taxes (other than consumption taxes and personal income taxes), fees, production entitlements, bonuses, dividends (other than ordinary dividends paid to shareholders), infrastructure improvement payments and other prescribed categories of payments.

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. The risks set out below are not an exhaustive list and should not be taken as a complete summary or description of all the risks associated with the Corporation's business and the oil and natural gas business generally.

Prices, Markets and Marketing

Various factors may adversely impact the marketability of oil, natural gas and NGLs, affecting net production revenue, production volumes and development and exploration activities.

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,

natural gas and NGLs 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, natural gas and NGLs are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil, natural gas and NGLs, 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") and other oil and gas exporting nations, 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, natural gas and NGLs are also subject to the availability of foreign markets and the Corporation's ability to access such markets. 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 associated NGLs 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, natural gas and NGLs 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, natural gas and NGLs 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, increased growth of shale oil production in the United States, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries and ongoing credit and liquidity concerns. Volatile oil, natural gas and NGLs 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

Weakness and volatility in the market conditions for the oil and gas industry may affect the value of the Corporation's reserves, restrict its cash flow and its ability to access capital to fund the development of its properties.

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 political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. In addition, the inability to get the necessary approvals to build pipelines, liquefied natural gas plants 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 and sold 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 restrict the Corporation's cash flow resulting in less funds from operations being available to fund the Corporation's 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 its 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. In addition to possibly resulting in a decrease in the value of the Corporation's economically recoverable reserves, lower commodity prices may also result in a decrease in the value of the Corporation's infrastructure and facilities, all of which could also have the effect of requiring a write down of the carrying value of the Corporation's oil and gas assets on its balance sheet and the recognition of an impairment charge in its income statement. 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

The Corporation's business may be adversely affected by recent political and social events and decisions made in the United States, Europe and elsewhere.

The Corporation's business may be adversely affected by recent political and social events and decisions made in the United States, Europe and elsewhere.

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 2016 presidential campaign a number of election promises were made and the new American administration has begun taking steps to implement certain of these promises. The administration has announced withdrawal of the United States from the Trans-Pacific Partnership and Congress has passed sweeping tax reform, which, among other things, significantly reduces US corporate tax rates. This may affect competitiveness of other jurisdictions, including Canada. The North American Free Trade Agreement is currently under renegotiation and the result is uncertain at this time. The administration has also taken action with respect to reduction of regulation which may also affect relative competitiveness of other jurisdictions. It is unclear exactly what other actions the 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, the citizens of the United Kingdom recently 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 the market value of its Common Shares.

A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the oil and gas industry including the balance between economic development and environmental policy such as the potential impact of the recent change of government in British Columbia and announcements and actions by the government of British Columbia that may impact the completion of the Trans-Mountain Pipeline project and other infrastructure projects.

Exploration, Development and Production Risks

The Corporation's future performance may be affected by the financial, operational, environmental and safety risks associated with the exploration, development and production of oil and natural gas.

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 to 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 and Pipeline Systems

Lack of capacity and/or regulatory constraints on gathering and processing facilities and pipeline systems may have a negative impact on the Corporation's ability to produce and sell its oil and natural gas.

The Corporation delivers its products through gathering and processing facilities and pipeline systems. 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 and pipeline systems. The lack of availability of capacity in any of the gathering and processing facilities and pipeline systems 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. Announcements and actions taken by the governments of British Columbia and Alberta relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. In addition, while the federal government has recently introduced draft legislation to overhaul the existing environmental assessment process and replace the NEB with a new regulatory agency, the impact of the new proposed regulatory scheme on proponents and the timing of receipt of approvals of major projects remains unclear.

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. Midstream and pipeline companies may take actions to maximize their return on investment which may in turn adversely affect producers and shippers, especially when combined with a regulatory framework that may not always align with the interests of particular shippers.

Pipeline Systems

Pipeline interruptions or capacity constraints may have a negative impact on the Corporation's ability to transport and market its products.

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 and Canadian Mainline systems.

Project Risks

The success of the Corporation's operations may be negatively impacted by factors outside of its control resulting in operational delays, cost overruns and marketing challenges.

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, natural gas and NGLs 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 and hydraulic fracturing, 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.

Reserves Estimates

The Corporation's estimated proved and proved plus probable reserves are based on numerous factors and assumptions which may prove incorrect and which may affect the Corporation.

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGLs 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, natural gas and NGLs 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, natural gas and NGLs;
- 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, natural gas and NGLs 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, natural gas and NGLs, 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, natural gas and NGLs 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

Hedging activities expose the Corporation to the risk of financial loss and counter-party risk.

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, or to diversify commodity price risk to multiple markets. However, to the extent that the Corporation engages in price risk management activities to protect itself from commodity price declines or to diversify commodity price risk, 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.

Credit Facility Arrangements

Failing to comply with covenants under the Corporation's credit facility could result in restricted access to capital or being required to repay all amounts owing thereunder.

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 default under the Corporation's credit facility, which could result in the Corporation being required to repay amounts owing thereunder. 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, repurchasing or making other distributions with respect to the Corporation's securities, incurring additional indebtedness, providing guarantees, the assumption of loans, making capital expenditures, entering into amalgamations, mergers, take-over bids or disposing of assets, among others.

The Corporation's lenders use the Corporation's reserves, commodity prices, applicable discount rate and other factors to periodically determine the Corporation's borrowing base. Commodity prices continue to be depressed and have fallen dramatically since 2014, and while prices have recently increased they remain volatile as a result of various

factors including actions taken to limit OPEC and non-OPEC production and increasing production by US shale producers. Depressed commodity prices could reduce the Corporation's borrowing base, reducing the funds available to the Corporation under the credit facility. This could result in the requirement to repay a portion, or all, of the Corporation's indebtedness.

If the Corporation's lenders require repayment of all or portion of the amounts outstanding under its credit facilities for any reason, including for a default of a covenant or the reduction of a borrowing base, there is no certainty that the Corporation would be in a position to make such repayment. Even if the Corporation is able to obtain new financing in order to make any required repayment under its credit facilities, 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 facilities could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness.

Forward-Looking Information

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*". 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's access to capital may be limited or restricted as a result of factors related and unrelated to it, impacting its ability to conduct future operations, acquire and develop reserves.

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil, natural gas and NGLs 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 appetite 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 may require additional financing from time to time to fund the acquisition, exploration and development of properties and its ability to obtain such financing in a timely fashion and on acceptable terms may be negatively impacted by the current economic and global market volatility.

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

Changes to royalty regimes may negatively impact the Corporation's cash flows.

There can be no assurance that the governments in the jurisdictions in which the Corporation has assets 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*".

Geo-Political Risks

Global political events may adversely affect commodity prices which in turn affect the Corporation's cash flow.

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.

Eco-Terrorism Risks

The Corporation's properties may be subject to terrorist attack.

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.

Management of Growth

The Corporation may not be able to effectively manage the growth of its business.

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

Loss of key personnel would negatively impact the Corporation's operations.

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

Breaches of the Corporation's cyber-security and loss of, or access to, electronic data may adversely impact its operations and financial position.

The Corporation has become increasingly dependent upon the availability, capacity, reliability and security of our information technology infrastructure and our 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 our land base, manage financial resources, analyze seismic information, administer our contracts with our 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 our business activities or our competitive position. In addition, cyber phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames, passwords, and credit card details (and money) by disguising as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. If the Corporation becomes a victim to a cyber phishing attack it could result in a loss or theft of the Corporation's financial resources or critical data and information or could result in a loss of control of the Corporation's technological infrastructure or financial resources. The Corporation applies technical and process controls in line with industry-accepted standards to protect our information assets and systems; however, these controls may not adequately prevent cyber-security breaches. Disruption of critical information technology services, or breaches of information security, could have a negative effect on our performance and earnings, as well as on our reputation. 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 the Common Share may be adversely affected by factors related and unrelated to the oil and natural gas industry.

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. 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, including governmental regulatory actions or adverse changes in general market conditions or economic trends. In certain jurisdictions institutions, including government sponsored entities, have determined to decrease their ownership in oil and gas entities which may impact the liquidity of certain securities and may put downward pressure on the trading price of those securities. Similarly, the market price of the Common Shares could be subject to significant fluctuations in response to variations in the Corporation's operating results, financial condition, liquidity and other internal factors, as well as the Corporation's operating results failing to meet the expectations of securities analysts or investors in any quarter, downward revision in securities analysts' estimates, acquisitions, dispositions or other material public announcements by the Corporation or its competitors, along with a variety of additional factors. Accordingly, the price at which the Common Shares will trade cannot be accurately predicted.

Impact of Future Financings on Market Price

The Corporation's future financings may negatively impact the market price of the Common Shares.

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 issue additional Common Shares, diluting current Shareholders.

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 Corporation competes with other oil and natural gas companies, some of which have greater financial and operational resources.

The oil and gas 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.

Environmental

Compliance with environmental regulations requires the dedication of a portion of the Corporation's financial and operational resources.

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.

Disposal of Fluids Used in Operations

Regulations regarding the disposal of fluids used in the Corporation's operations may increase its costs of compliance or subject it to regulatory penalties or litigation.

The safe disposal of the hydraulic fracturing fluids (including the additives) and water recovered from oil and natural gas wells is subject to ongoing regulatory review by the federal and provincial governments, including its effect on fresh water supplies and the ability of such water to be recycled, amongst other things. While it is difficult to predict the impact of any regulations that may be enacted in response to such review, the implementation of stricter regulations may increase the Corporation's costs of compliance.

Carbon Pricing Risk

Taxes on carbon emissions affect the demand for oil and natural gas, the Corporation's operating expenses and may impair the Corporation's ability to compete.

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*". In Canada, the federal and certain provincial governments have implemented legislation aimed at incentivizing the use of alternative fuels and in turn reducing carbon emissions. The taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products and at the same time, increasing the Corporation's operating expenses, each of which may have a material adverse effect on the Corporation's profitability and financial condition. Further, the imposition of carbon taxes puts the Corporation at a disadvantage with its counterparts who operate in jurisdictions where there are less costly carbon regulations.

Climate Change

Compliance with greenhouse gas emissions regulations may result in increased operational costs to the Corporation.

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 signatory to the Paris Agreement, which was ratified in Canada on October 3, 2016, the Government of Canada pledged to cut its GHG emissions by 30 per cent from 2005 levels by 2030. One of the pertinent policies announced to date by the Government of Canada to reduce GHG emission is the planned implementation of a nation-wide price on carbon emissions. Provincially, the Government of Alberta has already implemented a carbon levy on almost all sources of GHG emissions, now at a rate of \$30 per tonne. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Some of the Corporation's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the affect of increasing the Corporation's operating expenses and in the long-term reducing the demand for oil and gas production resulting in a decrease in the Corporation's profitability and a reduction in the value of its assets or asset write-offs. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*".

Regulatory

Modification to current or implementation of additional regulations may reduce the demand for oil and natural gas and/or increase the Corporation's costs and/or delay planned operations.

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. 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. Recently, the federal government and certain provincial governments have taken steps to initiate protocols and regulations to limit the release of methane from oil and gas operations. Such draft regulations and protocols may require additional expenditures or otherwise negatively impact the Corporation's operations, which may affect the Corporation's profitability. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulations*".

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 municipal, 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.

Hydraulic Fracturing

Implementation of new regulations on hydraulic fracturing may lead to operational delays, increased costs and/or decreased production volumes, adversely affecting the Corporation's financial position.

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

Variations in foreign exchange rates and interest rates could adversely affect the Corporation's financial condition.

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.

Changing Investor Sentiment

Changing investor sentiment towards the oil and gas industry may impact the Corporation's access to, and cost of, capital.

A number of factors, including the concerns of the effects of the use of fossil fuels on climate change, concerns of the impact of oil and gas operations on the environment, concerns of environmental damage relating to spills of petroleum products during transportation and concerns of indigenous rights, have affected certain investors' sentiments towards investing in the oil and gas industry. As a result of these concerns, some institutional, retail and public investors have announced that they no longer are willing to fund or invest in oil and gas properties or companies or are reducing the amount thereof over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices. Developing and implementing such policies and practices can involve significant costs and require a significant time commitment from the Board, management and employees of the Corporation. Failing to implement the policies and practices as requested by institutional investors may result in such investors reducing their investment in the Corporation or not investing in the Corporation at all. Any reduction in the investor base interested or willing to invest in the oil and gas industry and more specifically, the Corporation, may result in limiting the Corporation's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Common Shares.

Insurance

Not all risks of conducting oil and natural gas opportunities are insurable and the occurrence of an uninsurable event may have a materially adverse effect on the Corporation.

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 is exposed to credit risk of third party operators or partners of properties in which it has an interest.

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 oil, natural gas and NGLs 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

Liability management programs enacted by regulators in the western provinces may prevent or interfere with the Corporation's ability to acquire properties or require a substantial cash deposit with the regulator.

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 regulatory obligations. These programs 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 generally required. Changes to the required ratio of the Corporation's deemed assets to deemed liabilities or other changes to the requirements of liability management programs may result in significant increases to the Corporation's compliance obligations. In addition, the liability management regime may prevent or interfere with the Corporation's ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and 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)*, found an operational conflict between the *Bankruptcy and Insolvency Act* and the AER's abandonment and reclamation powers when the licensee is insolvent, which was affirmed by a majority of the Alberta Court of Appeal, and has been appealed by the AER to the Supreme Court of Canada for final determination. In response to the decision, the AER issued interim rules to administer the liability management program and until the Government of Alberta can develop new regulatory measures to adequately address environmental liabilities. There remains a great deal of uncertainty as to what new regulatory measures will be developed by the provinces or in concert with the federal government, as the final ruling will become binding in all

Canadian jurisdictions. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs*".

Tax Horizon

The Corporation's projections regarding its tax horizons may be inaccurate, resulting in a requirement to pay taxes sooner than expected.

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

The successful operation of a portion of the Corporation's properties is dependent on third parties.

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

Defects in the title to the Corporation's properties may result in a financial loss.

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 Licenses and Leases

The Corporation or its working interest partners may fail to meet the requirements of a licence or lease, causing its termination or expiry.

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 anticipated benefits of acquisitions may not be achieved and the Corporation may dispose of non-core assets for less than their carrying value on the financial statements as a result of weak market conditions.

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.

Reputational Risk Associated with the Corporation's Operations

The Corporation relies on its reputation to continue its operations and to attract and retain investors and employees.

Any environmental damage, loss of life, injury or damage to property caused by the Corporation's operations could damage the Corporation's reputation in the areas in which the Corporation operates. Negative sentiment towards the Corporation could result in a lack of willingness of municipal authorities being willing to grant the necessary licenses or permits for the Corporation to operate its business and in residents in the areas where the Corporation is doing business opposing further operations in the area by the Corporation. If the Corporation develops a reputation of having an unsafe work site it may impact the ability of the Corporation to attract and retain the necessary skilled employees and consultants to operate its business. Further, the Corporation's reputation could be affected by actions and activities of other corporations operating in the oil and gas industry, over which the Corporation has no control. In addition, environmental damage, loss of life, injury or damage to property caused by the Corporation's operations could result

in negative investor sentiment towards the Corporation, which may result in limiting the Corporation's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Common Shares.

Issuance of Debt

Increased debt levels may impair the Corporation's ability to borrow additional capital on a timely basis to fund opportunities as they arise.

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

Conflicts of interest may arise for the Corporation's directors and officers who are also involved with other industry participants.

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 or 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 to 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 Corporation's ability to successfully implement new technologies into its operations in a timely and efficient manner will affect its ability to compete.

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.

Alternatives to and Changing Demand for Petroleum Products

Changes to the demand for oil and natural gas products and the rise of petroleum alternatives may negatively affect the Corporation's financial condition, results of operations and cash flow.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and renewable energy generation devices could reduce the demand for oil, natural gas and liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or

incentives to decrease the use of fossil fuels and encourage the use of renewable fuel alternatives, which may lessen the demand for petroleum products and put downward pressure on commodity prices. In addition, advancements in energy efficient products have a similar affect on the demand for oil and gas products. 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 by decreasing the Corporation's profitability, increasing its costs, limiting its access to capital and decreasing the value of its assets.

Litigation

The Corporation may be involved in litigation in the course of its normal operations and the outcome of the litigation may adversely affect the Corporation and its reputation.

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

Breach of confidentiality by a third party could impact the Corporation's competitive advantage or put it at risk of litigation.

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

Material weaknesses in the Corporation's internal controls may negatively affect the Corporation and the market price of the Common Shares.

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

Taxation authorities may reassess the Corporation's tax returns.

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

Restrictions on the availability of and access to drilling equipment may impede the Corporation's exploration and development activities.

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 and Extreme Weather Conditions

Oil and natural gas operations are subject to seasonal and extreme weather conditions and the Corporation may experience significant operational delays as a result.

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. Road bans and other restrictions generally result in a reduction of drilling and exploratory activities and may also result in the shut-in of some of the Corporation's production if not otherwise tied-in. 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, cause operational difficulties including damage to machinery or contribute to personnel injury because of dangerous working conditions.

Aboriginal Claims

Aboriginal claims may affect the Corporation.

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.

Dividends

The Corporation does not pay dividends and there is no assurance that it will do so in the future.

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

Expanding the Corporation's business exposes it to new risks and uncertainties.

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, 2017.

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 5 day of March, 2018

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, 2017. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2017, estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.
3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook 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, 2017, 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, 2017	Canada	-	\$2,549,991	-	\$2,549,991
Totals			-	\$2,549,991	-	\$2,549,991

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:

Sroule Associates Limited
Calgary, Alberta, Canada
February 7, 2018

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, C.E.Ts.
Brent A. Hawkwood, P. Eng.
Senior Technologist