ADVANTAGE

OIL & GAS LTD.

ANNUAL INFORMATION FORM

YEAR ENDED DECEMBER 31, 2014

March 25, 2015

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GLOSSARY OF TERMS

Selected Defined Terms

"**5.00% Debentures**" means the 5.00% convertible unsecured subordinated debentures of the Corporation that matured on January 30, 2015;

"**2012 Secondary Offering**" means the secondary offering by Advantage of 8,300,000 common shares of Longview at a price of $9.00 per common share, which closed on May 22, 2012;

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

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

"**AOG**" or "**Advantage**" or the "**Corporation**" means Advantage Oil & Gas Ltd., a corporation amalgamation 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;

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

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

"**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;

"**Longview Transaction**" means the purchase by Longview from Advantage of certain oil-weighted assets for consideration comprised of cash and 29,450,000 common shares of Longview;

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

"**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

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

"**Current Production**" means average daily gross production for the three month period ended December 31, 2014;

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

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

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

"**development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

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

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

(d) provide improved recovery systems;

"**exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to as "prospecting costs") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively referred to as "geological and geophysical costs");

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells;

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

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

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

"**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;

"**net**" means:

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

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

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

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

"**Oil and Natural Gas Properties**" or "**Properties**" means the working, royalty or other interests of AOG in any petroleum and natural gas rights, tangibles and miscellaneous interests, including properties which may be acquired by AOG from time to time;

"**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: (i) analysis of drilling, geological, geophysical and engineering data; (ii) the use of established technology; and (iii) 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;

"**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

Oil and Natural Gas Liquids		Natural Gas	
bbls	barrels	Mcf	thousand cubic feet
Mbbls	thousand barrels	MMcf	million cubic feet
MMbbls	million barrels	bcf	billion cubic feet
NGLs	natural gas liquids	Mcf/d	thousand cubic feet per day
stb	stock tank barrels of oil	MMcf/d	million cubic feet per day
Mstb	thousand stock tank barrels of oil	MMcfe/d	million cubic feet equivalent per day
MMboe	million barrels of oil equivalent	m^3	cubic metres
boe/d	barrels of oil equivalent per day	MMbtu	million British Thermal Units
bbls/d	barrels of oil per day	GJ	Gigajoule

Other

BOE or boe	means barrel of oil equivalent, using the conversion factor of 6 Mcf of natural gas being equivalent to one bbl of oil.
mcfe	means thousand cubic feet of natural gas equivalent, using the ratio of 6 Mcf of natural gas being equivalent to one bbl of oil.
mmcfe	means million cubic feet of natural gas equivalent, using the ratio of 6 Mcf of natural gas being equivalent to one bbl of oil.
WTI	means West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for the crude oil standard grade
°API	means the measure of the density or gravity of liquid petroleum products derived from a specific gravity.
psi	means pounds per square inch.

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.

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

CONVERSION

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

To Convert From	To	Multiply By
Mcf	cubic metres	28.317
cubic metres	cubic feet	35.315
bbls	cubic metres	0.159
cubic metres	bbls	6.289
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
gigajoules	MMbtu	0.950
MMbtu	gigajoules	1.0526

FORWARD-LOOKING STATEMENTS

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

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

- the performance characteristics of our assets;
- oil and natural gas production levels;
- the size of the oil and natural gas reserves;
- projections of market prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- drilling plans;
- estimated timing of capital expenditures;
- future development plans for the Corporation's assets, including the anticipated timing thereof;
- targeted production at Glacier and the anticipated timing of achievement of such targets;
- management's belief that significant growth at Glacier exists beyond 2017;
- focus of capital budget;
- timing of development of undeveloped reserves;
- future abandonment and reclamation costs;
- tax horizons;
- anticipated review of the Corporation's Credit Facility;
- treatment under governmental regulatory regimes and tax laws; and
- capital expenditures programs.

Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources 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:

- volatility in market prices for oil and natural gas;
- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- fluctuation in foreign exchange or interest rates;
- stock market volatility and market valuations;
- changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry;

- geological, technical, drilling and processing problems and other difficulties in producing petroleum reserves; and
- the other factors discussed under "*Risk Factors*".

Although the forward-looking statements contained in this annual information form are based upon assumptions which AOG believe to be reasonable, AOG 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, AOG has made assumptions regarding, but not limited to: current commodity prices and royalty regimes; availability of skilled labour; timing and amount of capital expenditures; future exchange rates; the price of oil and natural gas; 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 oil and 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; and 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.

AOG 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 AOG will derive therefrom.

These forward-looking statements are made as of the date of this annual information form and AOG 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 standardized meaning prescribed under GAAP. These financial measures include funds from operations and cash netbacks. Management believes that these financial measures are useful supplemental information to analyze operating performance and provide an indication of the results generated by the Corporation's principal business activities. Investors should be cautioned that these measures should not be construed as an alternative to net income, comprehensive income, and cash provided by operating activities or other measures of financial performance as determined in accordance with GAAP. Advantage's method of calculating these measures may differ from other companies, and accordingly, they may not be comparable to similar measures used by other companies.

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. 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 AOG 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, 2014, the Corporation did not have any material direct or indirect subsidiaries, as the total assets and sales and operating revenues of the Corporation's subsidiaries, on a combined basis, does not exceed 10% of the consolidated assets and the consolidated sales and operating revenues of the Corporation.

GENERAL DEVELOPMENT OF THE BUSINESS

General

The Corporation and its subsidiaries are actively engaged in the business of 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.

A detailed description of the historical development of the business of the Corporation and its subsidiaries is outlined below. Unless the context otherwise requires, references to "we", "us", "our" or similar terms refer to the Corporation.

Three Year History

2012

Credit Facilities

On May 17, 2012, Advantage announced that the borrowing base under its credit facilities (the "**Credit Facilities**") had been increased from $275 million to $300 million, comprised of a $20 million revolving operating loan facility and a $280 million extendible revolving credit facility. Various borrowing options are available under the Credit Facilities, including prime rate based advances, U.S. base rate advances, U.S. dollar LIBOR advances and bankers' acceptances loans. The Credit Facilities are secured by a $1 billion floating charge demand debenture, a general security agreement and a subordination agreement from the Corporation covering all assets and cash flows. The amounts available to the Corporation from time to time under the Credit Facilities are based upon the borrowing base determined by the lenders and which is redetermined on a semi-annual basis by those lenders. The borrowing base constitutes a revolving facility for a 364 day term which is extendible annually for a further 364 day revolving period, subject to a one year term maturity as to lenders not agreeing to such annual extension.

2012 Secondary Offering

On May 22, 2012, Longview closed the 2012 Secondary Offering, pursuant to which 8,300,000 common shares of Longview held by Advantage were sold at a price of $9.00 per common share for aggregate gross proceeds to Advantage of $74,700,000. As a result of the 2012 Secondary Offering, Advantage retained an equity ownership interest of approximately 45.2% of the common shares of Longview. All of the net proceeds from the 2012 Secondary Offering were initially used to reduce indebtedness under the Credit Facilities. Funds were subsequently utilized to finance additional delineation drilling and development of the Middle Montney formation at Glacier.

Non-Core Asset Dispositions

On August 22, 2012, Advantage announced that it had engaged RBC Capital Markets to market for sale all of the Corporation's non-core assets, being all corporate assets excluding Advantage's core Glacier Montney natural gas asset and its common shares of Longview. The non-core assets produced a total of approximately 6,350 boe/d (80% gas and 20% oil and NGL) during 2012 and had 27.8 MMboe of proved plus probable reserves as at December 31, 2012. Advantage completed two non-core asset dispositions during the third quarter of 2012 for net cash proceeds of $10.9 million and a third non-core asset disposition during the fourth quarter of 2012 for net cash proceeds of $3.0 million (collectively, the "**2012 Non-Core Asset Dispositions**").

2013

Non-Core Asset Dispositions

On February 5, 2013, Advantage announced that it had completed a fourth non-core asset disposition in the first quarter of 2013 for net cash proceeds of $13.9 million and entered into a definitive agreement (the "**Purchase and Sale Agreement**") with Questfire Energy Corp. (the "**Purchaser**") for the sale of non-core assets representing production of approximately 5,900 boe/d (the "**Transaction**") for consideration consisting of $40.2 million of cash, a $32.6 million convertible senior secured debenture (the "**Questfire Debenture**") and 1.5 million Class B shares (the "**Class B shares**"). The Transaction closed on April 30, 2013.

The net cash proceeds from all five transactions were used to reduce outstanding bank indebtedness under the Credit Facilities. Upon closing of all five transactions, Advantage's major asset was its Glacier Montney property, with production of 90 MMcf/d to 100 MMcf/d, the Corporation's 45.1% holding of the issued and outstanding common shares of Longview, and the Questfire Debenture and Class B Shares issued pursuant to the Transaction.

Appointment of Financial Advisors and Strategic Alternatives Process

Advantage announced on February 5, 2013 that it had retained FirstEnergy Capital Corp. ("**FirstEnergy**") and RBC Capital Markets ("**RBC**") as co-advisors to provide advice as the Corporation initiated the review of strategic alternatives. The Board of Directors believed that the Corporation's core Glacier asset was materially undervalued in the context of the Corporation's current market valuation and Advantage committed to evaluating all options to maximize shareholder value. On February 26, 2013, the Corporation formed a special committee of independent directors (the "**Special Committee**") comprised of Mr. Steven Sharpe, as Chairman and Messrs. Stephen Balog and Ronald McIntosh, to oversee the strategic alternatives review process with the assistance of its financial advisors, FirstEnergy and RBC. The financial advisors commenced a broad marketing effort to solicit interest in a sale of the Corporation or other strategic transaction to maximize value for all shareholders. Technical presentations were completed and following the bid date, the Corporation, along with its financial advisors, reviewed the proposals received from those parties who submitted bids.

Credit Facilities

On April 30, 2013, Advantage announced that the borrowing base under the Credit Facilities had been reduced to $230 million, comprised of a $20 million revolving operating loan facility and a $210 million extendible revolving credit facility. The Credit Facilities were also amended to extend the duration of commodity hedging for up to four years and increase the permitted production available to hedge to 65% of total estimated crude oil and natural gas production on an annual basis over the first three years and 50% over the fourth year.

On October 24, 2013, Advantage announced that its lenders completed their semi-annual review and the borrowing base under the Credit Facilities had been increased to $300 million.

Changes in Directors and Management

On June 12, 2013, Ms. Sheila O'Brien resigned as a director of Advantage. On August 1, 2013, Mr. Kelly Drader resigned as Chief Financial Officer and a director of the Corporation to focus on his role as President and Chief Executive Officer of Longview. Mr. Craig Blackwood, the Vice-President Finance of the Corporation, assumed the role of Interim Chief Financial Officer and on February 4, 2014, Mr. Blackwood was appointed as Chief Financial

Officer of the Corporation. On November 28, 2013, Mr. Lionel Derochie resigned as Vice President Operations of the Corporation and on December 31, 2013, Mr. Pat Cairns resigned as Senior Vice President of the Corporation in order to focus on their respective roles at Longview.

2014

Strategic Alternatives Process Conclusion

On February 4, 2014, the Corporation announced that its strategic alternatives review process had been completed and did not result in an acceptable proposal. During the process, the Corporation received expressions of interest in respect of a variety of potential transactions; however, none of these proposals were determined to be in the best interests of the Corporation and did not adequately reflect the intrinsic value of the Corporation based upon its assets, operations and prospects for growth.

Three Year Development Plan and Glacier Phase VII Budget Approval

On February 4, 2014, the Corporation announced a three year development plan through to 2017 endorsed by the Board and approval of the Glacier Phase VII Capital and Operating Budget for the 12 months ending March 31, 2015. The Corporation's development plan targets doubling production at Glacier to 245 mmcfe/d (40,800 boe/d) in 2017 including the extraction of natural gas liquids. Based on well results and cost performance, Advantage expected this plan to be completed within its existing Credit Facilities with total capital expenditures during each 12 month development period to be between $210 million to $270 million with the drilling of approximately 33 wells per 12 month period. The Board approved the Phase VII Glacier capital budget targets to increase current production to approximately 183 mmcfe/d in the second quarter of 2015 including approximately 900 bbls/d of natural gas liquids from an initial 25 mmcf/d development in the Middle Montney. Facility expenditures include additional compression, acid gas compression, and power generation. A shallow cut liquids extraction process capable of accommodating future liquids rich gas production growth will be installed at Advantage's current Glacier Gas Plant. Management of Advantage believes significant growth potential exists beyond 2017 supported by the quality and size of Advantage's Montney resource and availability of future pipeline transportation capacity.

Termination of Technical Services Agreement

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

Credit Facilities

On May 29, 2014, Advantage announced that its lenders completed their annual review and the borrowing base under the Credit Facilities had been increased to $400 million.

Change in Directors and Management

On February 4, 2014, Mr. Steven Sharpe resigned from the Board. Mr Ron McIntosh was elected Chairman.

On March 27, 2014, Mr. Neil Bokenfohr, Vice-President Exploitation was appointed as Senior Vice President.

On May 26, 2014, Mr. Grant Fagerheim was appointed as a director of the Corporation.

2014 Secondary Offering

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

Sale of Questfire Investments

On March 26, 2014, Advantage entered an agreement for Questfire to redeem the Questfire Debenture at an aggregate purchase price of $13.6 million. In the second quarter of 2014, Questfire also purchased, pursuant to an issuer bid, all of the Class B Shares held by Advantage at a purchase price of $2.60 per share for gross proceeds of $3.9 million.

Recent Developments

2015 Guidance and Development Plan Update

On February 17, 2015, Advantage announced that the Board had approved a $110 million reduction in the Corporation's 2015 capital program. The Corporation also announced that despite the $110 million capital reduction, it would still 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 are required than were originally scheduled for the 2015 through 2017 period. This has resulted in a $150 million reduced capital program for the entire 2015 to 2017 development period.

Anticipated Changes in the Business

As at the date hereof and other than as disclosed herein, we do not anticipate that any material change in our business will occur during the balance of the 2015 financial year. See "*General Development of the Business – Recent Developments*".

Significant Acquisitions

The Corporation did not complete any acquisitions during the year ended December 31, 2014 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

AOG and its subsidiaries are actively engaged in the business of gas exploitation, development, acquisition and production in the Province of Alberta.

Advantage's exploitation and development program is focused at Glacier, Alberta where it is developing a significant natural gas resource play. As current and future practice, AOG 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 oil and gas asset acquisitions, as well as through corporate acquisitions. AOG targets acquisitions that support and augment its Montney development and long term strategy. It is currently intended that AOG will finance any acquisitions and investments through the Credit Facilities, the issuance of additional Common Shares from treasury and the issuance of subordinated convertible debentures or accessing long term debt instruments to maintain prudent leverage.

Reorganizations

As at the date hereof, except as disclosed herein, there have been no material reorganizations of AOG and or any of our subsidiaries within the three most recently completed financial years and there are currently no material reorganizations of AOG 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, 2014, the Corporation employed 27 full-time employees, 23 of which are located in the head office and 4 of which are located in the field. The Corporation also retained 5 consultants in the head office.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The report of management and directors on oil and gas disclosure in Form 51-101F3 and the report on consolidated reserves data by Sproule Associates Limited ("**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.

The consolidated statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated December 31, 2014. The effective date of the Statement is December 31, 2014 and the preparation date of the Statement is February 5, 2015.

Disclosure of Reserves Data

The reserves data set forth below (the "**Reserves Data**") is based upon an evaluation by Sproule with an effective date of December 31, 2014 contained in a consolidated report of Sproule dated February 5, 2015 (the "**Sproule Report**"). The Sproule Report evaluated, as at December 31, 2014, the oil, NGLs and natural gas reserves of AOG and its consolidated subsidiaries. The Reserves Data summarizes AOG's consolidated oil, NGLs and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs.

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.

All of our consolidated reserves are in Canada and, specifically, in the Province of Alberta.

There are numerous uncertainties inherent in estimating quantities of crude oil, natural gas and NGL reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this annual information form are estimates only. In general, estimates of economically recoverable oil and 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 natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its consolidated reserves will vary from estimates thereof and such variations could be material.

It should not be assumed that the 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 natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein.

The information relating to the Corporation's consolidated crude oil, NGL and 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, 2014
FORECAST PRICES AND COSTS

	RESERVES			
	LIGHT AND MEDIUM OIL		HEAVY OIL	
RESERVES CATEGORY	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**
PROVED				
Developed Producing	4.9	4.2		
Developed Non-Producing				
Undeveloped				
TOTAL PROVED	4.9	4.2		
PROBABLE	1.9	1.7		
TOTAL PROVED PLUS PROBABLE	6.8	5.9		

	RESERVES			
	NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**
PROVED				
Developed Producing	270,361	252,547	1,454.9	1,097.6
Developed Non-Producing	32,469	30,499	499.4	397.8
Undeveloped	798,870	751,264	6,487.5	5,167.0
TOTAL PROVED	1,101,700	1,034,310	8,441.8	6,662.3
PROBABLE	607,516	539,403	7,239.8	5,352.5
TOTAL PROVED PLUS PROBABLE	1,709,216	1,573,713	15,681.6	12,014.8

	RESERVES	
	TOTAL OIL EQUIVALENT	
RESERVES CATEGORY	**Gross (Mboe)**	**Net (Mboe)**
PROVED		
Developed Producing	46,519.9	43,193.0
Developed Non-Producing	5,910.9	5,480.9
Undeveloped	139,632.6	130,377.7
TOTAL PROVED	192,063.4	179,051.6
PROBABLE	108,494.5	95,254.6
TOTAL PROVED PLUS PROBABLE	300,557.9	274,306.2

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE

as at December 31, 2014
FORECAST PRICES AND COSTS

RESERVES CATEGORY	Before Income Tax Discounted at (%/year) 0% ($000's)	5% ($000's)	10% ($000's)	15% ($000's)	20% ($000's)	After Income Taxes Discounted at (%/year) 0% ($000's)	5% ($000's)	10% ($000's)	15% ($000's)	20% ($000's)	Unit Value Before Income Tax Discounted at 10%/ year(1) ($/boe)
PROVED											
Developed Producing	943,305	734,105	604,495	517,342	454,945	943,305	734,105	604,495	517,342	454,945	14.00
Developed Non-Producing	139,958	105,132	83,027	67,923	57,020	139,958	105,132	83,027	67,923	57,020	15.15
Undeveloped	2,595,789	1,274,441	671,513	362,609	190,146	2,211,331	1,104,349	589,310	320,145	167,035	5.15
TOTAL PROVED	3,679,052	2,113,679	1,359,035	947,875	702,111	3,294,594	1,943,586	1,276,833	905,410	679,000	7.59
PROBABLE	2,900,935	1,528,061	938,122	636,180	461,853	2,174,819	1,164,064	731,398	509,409	379,978	9.85
TOTAL PROVED PLUS PROBABLE	6,579,987	3,641,739	2,297,158	1,584,055	1,163,964	5,469,413	3,107,651	2,008,231	1,414,819	1,058,978	8.37

Notes:

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

(2) 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, 2014.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)

as at December 31, 2014
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE ($000's)	ROYALTIES ($000's)	OPERATING COSTS ($000's)	DEVELOP-MENT COSTS ($000's)	ABANDONMENT AND RECLAMATION COSTS ($000's)	FUTURE NET REVENUE BEFORE FUTURE INCOME TAXES ($000's)	FUTURE INCOME TAXES ($000's)	FUTURE NET REVENUE AFTER FUTURE INCOME TAXES ($000's)
Proved Reserves	6,769,642	508,549	1,093,073	1,442,382	46,586	3,679,052	384,458	3,294,594
Proved Plus Probable Reserves	11,105,042	1,073,966	1,654,935	1,736,227	59,927	6,579,987	1,110,574	5,469,413

Note:

(1) 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, 2014.

FUTURE NET REVENUE
BY PRODUCTION GROUP
as at December 31, 2014
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000's)	UNIT VALUE ($/boe)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	-	-
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	1,359,035	7.59
	Non-Conventional Oil and Gas Activities (Coalbed Methane)	-	-
	TOTAL	1,359,035	7.59
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	-	-
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	2,297,158	8.37
	Non-Conventional Oil and Gas Activities (Coalbed Methane)	-	-
	TOTAL	2,297,158	8.37

Pricing Assumptions

The following tables set forth the benchmark reference prices, as at December 31, 2014, reflected in the Reserves Data. These price assumptions were provided to us by Sproule and were Sproule's then current forecasts at the date of the Sproule Report.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS[(1)]
as at December 31, 2014
FORECAST PRICES AND COSTS

Year	Western Canada Select 20.5º API ($Cdn/bbl)	Canadian Light Sweet Crude Oil 40º API ($Cdn/bbl)	NATURAL GAS AECO-C Spot ($Cdn/MMBtu)	NATURAL GAS LIQUIDS Edmonton Pentanes Plus ($Cdn/bbl)	NATURAL GAS LIQUIDS Edmonton Butanes ($Cdn/bbl)	INFLATION RATES %/Year	EXCHANGE RATE [(2)] ($US/$Cdn)
2015	60.50	70.35	3.32	78.60	50.34	1.5	0.850
2016	75.13	87.36	3.71	97.60	62.51	1.5	0.870
2017	84.52	98.28	3.90	109.80	70.32	1.5	0.870
2018	85.79	99.75	4.47	111.44	71.37	1.5	0.870
2019	87.07	101.25	5.05	113.12	72.44	1.5	0.870
2020	89.31	103.85	5.13	116.02	74.31	1.5	0.870
2021	90.65	105.40	5.22	117.76	75.42	1.5	0.870
2022	92.01	106.99	5.31	119.53	76.55	1.5	0.870
2023	93.39	108.59	5.40	121.32	77.70	1.5	0.870
2024	94.79	110.22	5.49	123.14	78.87	1.5	0.870
2025	96.21	111.87	5.58	124.99	80.05	1.5	0.870
Thereafter	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	0.870

Notes:

(1) This summary table identifies benchmark reference pricing schedules that might apply to a *reporting issuer*.
(2) The exchange rate 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, 2014, were $4.15/Mcf for natural gas, $93.26/bbl for crude oil, and $66.97/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, 2014 against such reserves as at December 31, 2013 based on forecast prices and cost assumptions. This table does not include any reserves attributable to Longview as at December 31, 2013.

RECONCILIATION OF
GROSS RESERVES
BY PRODUCT TYPE
FORECAST PRICES AND COSTS

	Light And Medium Oil			Heavy Oil			Natural Gas Liquids		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2013	6.0	1.0	7.0	-	-	-	7,085.7	5,948.6	13,034.3
Extensions	-	-	-	-	-	-	502.0	1,447.3	1,949.3
Improved Recovery	-	-	-	-	-	-	-	-	-
Infill Drilling	-	-	-	-	-	-	137.0	55.8	192.8
Technical Revisions	(0.5)	0.9	0.4	-	-	-	771.0	(212.9)	551.8
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	3.5	1.0	4.5
Production	(0.6)	-	(0.6)	-	-	-	(57.4)	-	(57.4)
December 31, 2014	4.9	1.9	6.8	-	-	-	8,441.8	7,239.8	15,681.6

	Associated and Non-Associated Gas			Oil Equivalent		
FACTORS	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (MBoe)	Probable (MBoe)	Proved Plus Probable (MBoe)
December 31, 2013	992,325	626,508	1,618,833	172,479.2	110,367.6	282,846.8
Extensions	24,066	40,510	64,576	4,512.9	8,199.0	12,711.9
Improved Recovery	-	-	-	-	-	-
Infill Drilling	12,250	4,920	17,170	2,178.6	875.8	3,054.4
Technical Revisions	121,053	(64,178)	56,874	20,945.9	(10,908.4)	10,037.6
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	(314)	(243)	(557)	(48.8)	(39.6)	(88.4)
Production	(47,679)	-	(47,679)	(8,004.5)	-	(8,004.5)
December 31, 2014	1,101,700	607,516	1,709,216	192,063.4	108,494.4	300,557.7

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, 2014 against such reserves as at December 31, 2013 based on forecast prices and cost assumptions. This table represents the Corporation’s and the Corporation’s consolidated subsidiaries interest including 100% of Longview’s reserves at December 31, 2013. As a result of the 2014 Secondary Offering, the Longview reserves were removed from the Corporation’s consolidated reserves as represented in the following table as “dispositions” in 2014.

RECONCILIATION OF GROSS RESERVES BY PRODUCT TYPE FORECAST PRICES AND COSTS

FACTORS	Light And Medium Oil Proved (Mbbl)	Light And Medium Oil Probable (Mbbl)	Light And Medium Oil Proved Plus Probable (Mbbl)	Heavy Oil Proved (Mbbl)	Heavy Oil Probable (Mbbl)	Heavy Oil Proved Plus Probable (Mbbl)	Natural Gas Liquids Proved (Mbbl)	Natural Gas Liquids Probable (Mbbl)	Natural Gas Liquids Proved Plus Probable (Mbbl)
December 31, 2013	11,927.1	10,741.2	22,668.3	1,514.9	2,987.8	4,502.7	8,772.1	7,081.4	15,853.5
Extensions	-	-	-	-	-	-	502.0	1,447.3	1,949.3
Improved Recovery	-	-	-	-	-	-	-	-	-
Infill Drilling	-	-	-	-	-	-	137.0	55.8	192.8
Technical Revisions	(0.5)	0.9	0.4	-	-	-	771.0	(212.9)	551.8
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	(11,921.1)	(10,740.2)	(22,661.3)	(1,514.9)	(2,987.8)	(4,502.7)	(1,686.4)	(1,132.8)	(2,819.2)
Economic Factors	-	-	-	-	-	-	3.5	1.0	4.5
Production	(0.6)	-	(0.6)	-	-	-	(57.4)	-	(57.4)
December 31, 2014	4.9	1.9	6.8	-	-	-	8,441.8	7,239.8	15,681.6

FACTORS	Associated and Non-Associated Gas Proved (MMcf)	Associated and Non-Associated Gas Probable (MMcf)	Associated and Non-Associated Gas Proved Plus Probable (MMcf)	Oil Equivalent Proved (MBoe)	Oil Equivalent Probable (MBoe)	Oil Equivalent Proved Plus Probable (MBoe)
December 31, 2013	1,018,018	646,733	1,664,751	191,883.7	128,599.3	320,483.0
Extensions	24,066	40,510	64,576	4,512.9	8,199.0	12,711.9
Improved Recovery	-	-	-	-	-	-
Infill Drilling	12,250	4,920	17,170	2,178.6	875.8	3,054.4
Technical Revisions	121,053	(64,178)	56,874	20,945.9	(10,908.4)	10,037.6
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	(25,693)	(20,225)	(45,918)	(19,404.5)	(18,231.7)	(37,636.2)
Economic Factors	(314)	(243)	(557)	(48.8)	(39.6)	(88.4)
Production	(47,679)	-	(47,679)	(8,004.5)	-	(8,004.5)
December 31, 2014	1,101,700	607,516	1,709,216	192,063.4	108,494.4	300,557.7

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 two years. In some cases, it will take longer than two years to develop these reserves. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "*Risk Factors*" herein.

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

Proved Undeveloped Reserves

	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
Year	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
Prior thereto	224.0	2,843.0	-	90.0	358,734	1,055,875	42.0	918.0
2012	11.0	45.5	-	-	72,417	694,563	1,630.7	1,926.3
2013	-	-	-	-	43,846	759,424	923.4	6,084.0
2014	-	-	-	-	102,447	798,870	376.1	6,487.5

Sproule has assigned 139.6 MMboe of gross proved undeveloped reserves in the Sproule Report under forecast prices and costs, together with $1.4 billion of associated undiscounted future capital expenditures. Proved undeveloped capital spending in the first two forecast years of the Sproule Report accounts for $287.7 million, or 20.0%, of the total forecast. These figures increase to $620.7 million or 43.2%, during the first five years of the Sproule Report.

Probable Undeveloped Reserves

	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
Year	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
Prior thereto	661.0	5,496.0	-	2,121.0	113,885	756,991	29.0	1,023.0
2012	32.2	468.6	-	-	108,772	462,247	842.1	1,082.0
2013	-	-	-	-	31,827	547,577	1,109.4	5,367.1
2014	-	-	-	-	32,596	489,546	974.0	6,039.3

Sproule has assigned 87.6 MMboe of gross probable undeveloped reserves and has allocated future development capital of $291.8 million to all gross probable undeveloped reserves with $49.4 million scheduled for the first five years.

Significant Factors or Uncertainties

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.

Future Development Costs

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

	Forecast Prices and Costs	
Year	**Proved Reserves (MM$)**	**Proved Plus Probable Reserves (MM$)**
2015	128.5	156.1
2016	162.7	170.7
2017	139.3	139.3
2018	110.0	124.2
2019	85.2	86.9
Total: Undiscounted for all years	1,442.4	1,736.2

To fund our capital program, including future development costs, we have many financing alternatives available, including partial retention of cash flow from operations, bank debt financing, issuance of additional Common Shares, and issuance of convertible debentures. We evaluate the appropriate financing alternatives closely and have made use of all these options dependent on the given investment situation and the capital markets. We maintain a capital structure that is similar to our industry peer group and that are intended to maximize the investment return to Shareholders as compared to the cost of financing. We expect to continue using all financing alternatives available to continue pursuing our development strategy. The assorted financing instruments have certain inherent costs which we consider 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 our 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

AOG 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, 2014 unless otherwise noted and reserves quoted are as reported in the Sproule Report.

Glacier, Alberta

The Glacier property is located adjacent to the provincial boundary between Alberta and British Columbia and is between Grande Prairie, Alberta and Dawson Creek, British Columbia. The primary zones of interest are within the Triassic Montney and Doig formation siltstones. The Glacier property consists of 82 gross (76 net) sections of land with Doig/Montney interests. The total thickness of the Lower Doig/Montney is up to 300 metres and lends itself to multiple layers of development which contributes to the significant inventory of undrilled wells within this resource play. Based on current reserves assignments as of December 31, 2014, Glacier has a proved plus probable reserve life index ("RLI") of 37 years at a production rate of 133 MMcf/d, which was the average production rate achieved at Glacier during the fourth quarter of 2014.

Since the spud of the first horizontal well on July 26, 2008 to the end of December 2014, Advantage has drilled and completed 137 gross (127.5 net) horizontal wells at the Glacier property in either the Triassic Montney or Doig formation siltstones. In addition, two vertical wells drilled into the underlying Belloy Formation are used for acid gas disposal and two vertical wells are used as a service wells that support our water disposal system.

In 2014, Advantage drilled 38 gross (38 net) horizontal wells in the Montney and Lower Doig formations. Additionally, Advantage drilled one vertical well in the fourth quarter of 2014 proximal to our acid gas disposal scheme that will serve as a backup acid gas disposal well.

During 2014 Advantage acquired an additional 9 gross (9 net) sections of new Montney acreage in close proximity to the producing Glacier asset that will be evaluated for prospective natural gas and liquids potential. In aggregate Advantage now holds 129 net sections of land with either Doig or Montney potential for both natural gas and NGLs.

During 2014 and Q1 2015, Advantage continued with its program to delineate the Glacier land block vertically by drilling and testing wells in intervals other than the historically drilled Doig and Lower Montney. To date, a total of 16 horizontal wells and 3 vertical recompletions have tested intervals other than the Lower Doig or Lower Montney. This development has resulted in significant delineation and de-risking of the liquid rich Middle Montney resource potential at Glacier.

Advantage owns and operates a 100% working interest gas plant located at 5-02-76-12W6. The plant has a licenced throughput capacity of 160 MMcf/d of raw dry gas. A major expansion of the plant will be completed in July 2015 to increase the capacity to 260 MMcf/d including the addition of a shallow cut liquid extraction process. All gas is sold through Advantage’s 22 kilometer sales pipeline into the TransCanada pipeline system. The operating cost structure of the Glacier field is very favorable with combined field and plant operating costs averaging $0.32/Mcfe in 2014.

Glacier production is currently at approximately 135 MMcfe/d or 22,500 boe/d which represents virtually 100% of the Corporation's total production.

The Sproule Report assigns 1,097 bcf of gross (1,030 bcf of net) proved natural gas reserves and 8.3 MMbbls of gross (6.5 MMbbls of net) proved NGL reserves to this property. In addition, 606 bcf of gross (538 bcf of net) probable natural gas reserves and 7.2 MMbbls of gross (5.3 MMbbls of net) probable NGL reserves have been assigned to this property.

Oil and Gas Wells

The following table sets forth the number and status of wells as at December 31, 2014 in which we have a working interest.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	-	-	-	-	138	125	30	30

Properties with no Attributed Reserves

The following table sets out our unproved properties as at December 31, 2014.

	Gross Acres	Net Acres
Alberta	108,939	88,527

We expect that rights to explore, develop and exploit 960 net acres of our undeveloped land holdings will expire by December 31, 2015. The land expirations do not consider our 2015 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 operational results and financial condition will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely in recent years. Such prices are primarily determined by economic, and in the case of oil prices, political factors. Supply and demand factors, as well as weather, general economic conditions, and conditions in other oil and natural gas regions of the world also impact prices. Any upward or downward movement in oil and natural gas prices could have an effect on our financial condition and capital development.

Advantage approved a hedging policy using, amongst others, costless collars and fixed price swaps to hedge up to 65% of its gross oil, NGLs and natural gas production for a maximum period of three years and 50% over the fourth year. These hedging activities could expose the Corporation to losses or gains. To the extent that the Corporation engages in risk management activities related to commodity prices, it will be subject to credit risk associated with the parties with which it contracts. This credit risk will be mitigated by entering into contracts with only stable and creditworthy parties and through the frequent review of the Corporation's exposure to these entities. See "*Risk Factors*".

Advantage has the following derivatives in place:

Natural gas - AECO

Period	Average Production Hedged	Average Price AECO - $Cdn.
Q1 2015 to Q4 2015	82.9 MMcf/d	$3.86/Mcf
Q1 2016 to Q4 2016	84.1 MMcf/d	$3.69/Mcf
Q1 2017	80.6 MMcf/d	$3.65/Mcf

Additional Information Concerning Abandonment and Reclamation Costs

We estimate the costs to abandon and reclaim all our non-producing and producing wells, gas plants, pipelines, batteries, and other facilities. No estimate of salvage value is netted against the estimated cost. Our model for estimating the amount of future abandonment and reclamation expenditures was done on an individual well and facility level. Estimated expenditures for each well and facility are based on internal estimates through consultation with our Health, Safety and Environment Department. Each well and facility are assigned an average cost for abandonment and reclamation over a 60 year period. Timing of expenditures are based on budgets and estimates of such annual activities. Facility reclamation costs are generally scheduled to begin shortly before the end of the reserve life of our associated reserves and continue beyond the reserve life under the assumption that decommissioning of plant/facilities are generally mobile assets with a long useful life.

We estimate that we will incur reclamation and abandonment costs on 155 net producing and non-producing wells and 295 net abandoned wells. The approximate net cost to abandon and reclaim all wells and facilities, discounted at 10%, totals $16.6 million ($53.6 million undiscounted), of which approximately $1.6 million are included in the estimate of future net revenue ($59.9 million undiscounted). Abandonment and reclamation costs undiscounted and expected to be paid over the next three years totals $4.0 million.

Tax Horizon

In 2014, 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 AOG 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, 2014:

Capital Expenditures ($ thousands)	**2014**
Drilling, completions and workovers	$195,802
Well equipping and facilities	37,662
Land and seismic	-
Total expenditures on property, plant and equipment	233,464
Property Acquisition – Proved Properties	-
Property Acquisition – Unproved Properties	3,237
Property dispositions	-
Exploration costs	-
Development costs	-
Total capital expenditures	$236,701

Exploration and Development Activities

The following table sets forth the gross and net wells in which we participated during the year ended December 31, 2014:

	Exploratory		**Development**		**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Oil wells	-	-	-	-	-	-
Gas wells	-	-	38	38	38	38
Service wells	-	-	1	1	1	1
Dry holes	-	-	-	-	-	-
Total	-	-	39	39	39	39

Subject to, among other things, the availability of drilling rigs and weather that permits access to drill sites, in the first six months of 2015, we plan to drill 10 net wells and complete 6 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, 2015 reflected in the estimate of future net revenue disclosed in the tables contained under "*Disclosure of Reserves Data*".

	Light and Medium Oil (bbls/d)		Heavy Oil (bbls/d)		Natural Gas (Mcf/d)		Natural Gas Liquids (bbls/d)		Total (Boe/d)	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Proved Producing	1	1	-	-	145,045	136,548	510	467	24,685	23,226
Proved Developed Non-Producing	-	-	-	-	2,373	2,255	36	35	432	410
Proved Undeveloped	-	-	-	-	8,433	8,011	-	-	1,405	1,335
Total Proved	1	1	-	-	155,851	146,814	546	501	26,523	24,971
Total Probable	-	-	-	-	7,387	6,997	35	32	1,266	1,199
Total Proved Plus Probable	1	1	-	-	163,238	153,811	581	533	27,788	26,170

The following table indicates our production estimated from our important fields for the year ended December 31, 2015:

Properties	**Natural Gas (Mcf/d)**	**NGLs (bbls/d)**	**Crude Oil (bbls/d)**	**Total (boe/d)**
Alberta	163,238	581	1	27,788
Glacier	162,216	541	-	27,577

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 2014				Year Ended
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**Dec. 31, 2014**
Average Daily Production[(1)]					
Crude Oil (bbls/d)	154	188	125	88	138
Gas (Mcf/d)	122,481	134,912	131,553	133,433	130,627
NGLs (bbls/d)	10	12	36	25	21
Combined (mcfe/d)	123,465	136,112	132,519	134,111	131,581
Average Net Production Prices Received					
Crude Oil ($/bbl)	96.53	100.40	88.76	78.94	93.26
Gas ($/Mcf)	5.21	4.71	4.03	3.78	4.41
NGLs ($/bbl)	55.36	134.58	63.60	44.74	66.97
Combined ($/mcfe)	5.29	4.82	4.10	3.82	4.49
Gain/(Loss) on Derivatives					
Crude Oil ($/bbl)	-	-	-	-	-
Gas ($/mcfe)	(0.32)	(0.44)	(0.23)	(0.06)	(0.26)
Combined ($/mcfe)	(0.32)	(0.44)	(0.23)	(0.06)	(0.26)
Royalties Paid					
Crude Oil ($/bbl)	3.75	6.30	3.05	3.18	4.38
Gas ($/Mcf)	0.24	0.22	0.19	0.18	0.21
NGLs ($/bbl)	7.94	7.60	1.73	2.62	3.55
Combined ($/mcfe)	0.24	0.23	0.19	0.18	0.21

	Quarter Ended 2014				Year Ended
	Mar. 31	June 30	Sept. 30	Dec. 31	Dec. 31, 2014
Operating Expenses(2)(3)					
Crude oil ($/bbl)	1.56	1.62	1.98	2.52	1.86
Natural gas ($/Mcf)	0.28	0.31	0.35	0.34	0.32
NGLs ($/bbl)	2.34	3.48	1.14	1.44	1.68
Combined ($/mcfe)	0.28	0.31	0.35	0.34	0.32
Netback Received(4)					
Crude Oil ($/bbl)	91.22	92.48	83.73	73.24	87.02
Gas ($/Mcf)	4.37	3.74	3.26	3.20	3.62
NGLs ($/bbl)	45.08	123.50	60.73	40.68	61.74
Combined ($/mcfe)	4.45	3.84	3.33	3.24	3.70

Notes:

(1) Before deduction of royalties.
(2) This figure includes all field operating expenses.
(3) We do not record operating expenses on a commodity basis. Information in respect of operating expenses for crude oil and NGLs ($/bbl) and natural gas ($/Mcf) has been determined by allocating expenses on a relative volume of crude oil, NGLs and natural gas production basis.
(4) 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 (3) above.

The following table indicates our approximate average daily production from our important fields for the year ended December 31, 2014:

Properties	Natural Gas (Mcf/d)	NGLs (bbls/d)	Crude Oil (bbls/d)	Total (mcfe/d)
Alberta				
Glacier	129,980	-	132	130,772

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 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 renegotiated annually and run for one year and are cancellable on 30 days notice.

Cyclical and Seasonal Impact of Industry

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

Environmental Considerations

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

Health, Safety and Environmental

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

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

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

In 2014, the Corporation met the AER Enhanced Production Audit Program with a compliance rating for Glacier of 100% satisfactory, which exceeds the industry average, and Advantage's incident ratings in 2014 were significantly below industry averages. In addition, a reclamation certificate was received by Advantage in 2014. Advantage's spill volumes in the last three years were negligible.

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

Competitive Conditions

There is considerable competition in the worldwide oil and natural gas industry, including the Province of Alberta where the Company'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 AOG and positions for each of the directors and officers of AOG 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.

Name, Province and Country of Residence	Position Held and Period Served as a Director or Officer[(4)(5)]	Principal Occupations During Past Five Years
Ronald A. McIntosh[(2)(3)(7)] Alberta, Canada	Director since September 25, 1998[(6)] Chairman since February 4, 2014	Chairman of North American Energy Partners Inc., a publicly traded corporation and a director of Fortaleza Energy Inc., previously known as Alvopetro Inc., formerly named Fortress Energy Inc. Mr. McIntosh has extensive experience in the energy business. His previous roles included President and Chief Executive Officer of Navigo Energy, Chief Operating Officer of Gulf Canada, Vice President Exploration and International of PetroCanada and Chief Operating Officer of Amerada Hess Canada.
Stephen E. Balog[(1)(2)(3)] Alberta, Canada	Director since August 16, 2007	Principal of Alconsult International Ltd. and President, West Butte Management Inc., private consulting companies that provide technical and business advisory services to oil and gas operators. Prior thereto, President and Chief Operating Officer and a Director of Tasman Exploration Ltd. from 2001 to June, 2007. Mr. Balog has extensive oil and gas industry experience in the management and operation of senior and junior production companies. He was a key contributor to the development and use of the Canadian Oil & Gas Evaluation Handbook as an industry standard for reserves evaluation, and has previously served on the Petroleum Advisory Committee, Alberta Securities Commission.
Grant Fagerheim[(1)(2)] Alberta, Canada	Director since May 26, 2014	Chairman, President and Chief Executive Officer of Whitecap Resources Inc., a public oil and gas company, since June, 2008. Prior thereto, Mr. Fagerheim was the President and Chief Executive Officer and a Director of Cadence Energy Inc. (formerly, Kereco Energy Ltd.), a public oil and gas company, from January 2005 to September 2008. Mr. Fagerheim received his Bachelor's degree in Education (Economics Minor) from the University of Calgary in 1983 and attended the Executive MBA at Queen's University in 1995. Mr. Fagerheim currently sits on the board of directors of PRD Energy Inc., a public oil and gas company.
Paul Haggis[(1)(2)(3)] Alberta, Canada	Director since November 7, 2008	Mr. Haggis' was President and Chief Executive Officer of Ontario Municipal Employees Retirement System (OMERS) from September 2003 to March 2007, Interim Chief Executive Officer of the Public Sector Pension Investment Board (PSPIB) during 2003 and Executive Vice-President, Development and Chief Credit Officer of Manulife Financial in 2002. Mr. Haggis has extensive financial markets and public board experience having served on the Board of Directors of Canadian Tire Bank until March 30, 2012. He was a director and Chair of the Investment Committee of the Insurance Corporation of British Columbia and currently serves as an advisor to the committee. He was also Chair of the Audit Committee of C.A. Bancorp and Prime Restaurants Royalty Income Fund. Currently he is on the Board of UBC Investment Management Inc., Canadian Pacific Railway, Athabasca Oil Corporation and is Chairman of Alberta Enterprise Corp. Mr. Haggis holds a Bachelor of Arts degree from the University of Western Ontario and is certified as a Chartered Director through the Directors College at McMaster University.
Craig Blackwood Alberta, Canada	Vice President, Finance since January 27, 2009 and Chief Financial Officer since August 1, 2013	Chief Financial Officer of AOG since August 1, 2013. Vice President, Finance of AOG 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 AOG 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 AOG from June 23, 2006 to March 27, 2014. Vice-President, Exploitation of Longview from May 13, 2011 to November 7, 2013. Prior thereto, Vice President Exploitation and Operations of Ketch Resources Ltd. from January 2005 to June 2006; Vice President, Engineering of Bear Creek Energy Ltd. (and Crossfield Gas Corp. prior thereto) from March 2002 to January 2005. Prior thereto, Director of Exploitation for Calpine Canada Natural Gas Company from December 2000 to March 2002.
Jay P. Reid Alberta, Canada	Corporate Secretary, Since April, 2001	Partner at the Calgary based law firm of Burnet, Duckworth & Palmer LLP and has practiced corporate and securities law since 1990. He has served as a director or officer of a number of publicly listed issuers and currently serves as Corporate Secretary for Gear Energy Ltd., Madalena Energy Inc., Pinecrest Energy Inc. and a number of private 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) AOG does not have an executive committee of the Board.
(5) AOG'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 AOG 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.
(7) Mr. McIntosh is a director of Fortress Energy Inc. ("**Fortress**"). 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 Fortress and its assets and allowing Fortress to prepare a plan of arrangement for its creditors if necessary. Fortress took such step in order to enable Fortress to challenge a reassessment issued by the Canada Revenue Agency ("**CRA**"). As a result of the reassessment, if Fortress had not taken any action, it would have been compelled to immediately remit one half of the reassessment to the CRA and Fortress did not have the necessary liquid funds to remit, although Fortress had assets in excess of its liabilities with sufficient liquid assets to pay all other liabilities and trade payables. Fortress believed that the CRA's position was not sustainable and vigorously disputed the CRA's claim. Fortress 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 Fortress 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 Fortress due to Fortress 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 Fortress 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 Fortress 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 Fortress closed the sale of substantially all of its oil and gas assets. As a result of the sale Fortress was delisted from the TSX on March 30, 2011 as it no longer met minimum listing requirements. Fortress was renamed Alvopetro Inc. on November 24, 2012. Alvopetro Inc. was renamed Fortaleza Energy Inc. in November 2013.

As at March 25, 2015 the directors and executive officers of AOG, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 2,135,212 Common Shares, or approximately 1.25% of the issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Other than as disclosed above:

(a) no director or executive officer of AOG 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 AOG) 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 AOG or security holder holding a sufficient number of securities of AOG to affect materially the control of AOG 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 AOG) 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 AOG or securityholder holding a sufficient number of securities of AOG to affect materially the control of AOG 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 AOG or securityholder holding a sufficient number of securities of AOG to affect materially the control of AOG 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.

Conflicts of Interest

The directors and officers of AOG 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 25, 2015, other than as disclosed herein, the Corporation was not aware of any existing or potential material conflicts of interest between the Corporation and a subsidiary of the Corporation and a director or officer of the Corporation or of a subsidiary of the Corporation.

DIVIDEND POLICY

The Corporation does not anticipate paying dividends in the immediate future and will instead direct cash flow to capital expenditures and debt repayment. 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, 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, 2014, there were 170,067,650 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 AOG and to one vote at such meetings. The holders of Common Shares are, at the discretion of the AOG Board of Directors and subject to applicable legal restrictions, entitled to receive any dividends declared by the AOG Board of Directors on the Common Shares. The holders of Common Shares are entitled to share equally in any distribution of the assets of AOG upon the liquidation, dissolution, bankruptcy or winding-up of AOG 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 AOG 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 AOG 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 AOG, whether voluntary or involuntary, or any other distribution of the assets of AOG 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.

5.00% Debentures

On January 30, 2015, the 5.00% Debentures matured and the Corporation satisfied its obligation to repay to holders of the 5.00% Debentures the principal amount of all of the 5.00% Debentures outstanding on the maturity date, together with all accrued and unpaid interest thereon, in cash, with the exception of $10,000, which was converted by holders of the Debentures into 1,162 Common Shares prior to the maturity date.

The 5.00% Debentures paid interest semi-annually and were convertible at the option of the holder into Common Shares at the conversion price per Common Share noted below plus accrued and unpaid interest. The details of the 5.00% Debentures including the balance outstanding as at December 31, 2014 are as follows:

	5.00%
Trading symbol	AAV.DB.H
Issue date	Dec. 31, 2009
Maturity date	Jan. 30, 2015
Conversion price	$8.60
Outstanding	$86,250,000

PRICE RANGE AND TRADING VOLUME OF SECURITIES

Common Shares

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

Period	High	Low	Volume
	($)	($)	
TSX Trading			
2014			
January	4.93	4.41	3,733,590
February	4.62	3.84	17,534,261
March	5.62	4.29	14,217,697
April	6.98	5.47	26,075,688
May	7.06	6.04	11,457,784
June	7.85	6.67	14,332,107
July	7.18	5.66	13,442,752
August	6.93	5.71	10,382,010
September	6.72	5.45	14,907,859
October	5.77	4.54	12,909,255
November	5.85	4.54	12,594,250
December	6.24	4.51	12,852,501
2015			
January	5.75	4.94	7,959,456
February	7.27	5.19	9,097,369
March (1 to 25)	6.88	6.09	6,451,660
NYSE Trading (U.S.$)			
2014			
January	4.57	4.03	2,241,928
February	4.18	3.47	2,773,319
March	5.10	3.85	5,934,255
April	6.37	4.95	11,989,332
May	6.45	5.56	8,434,090
June	7.23	6.11	10,003,138
July	6.73	5.27	8,679,424
August	6.33	5.21	8,202,496
September	6.17	4.91	8,977,160
October	5.16	4.04	7,467,015
November	5.21	3.97	5,364,559
December	5.36	3.95	6,432,375
2015			
January	4.79	3.89	3,607,749
February	5.83	4.12	3,068,283
March (1 to 25)	5.49	4.72	2,918,920

5.00% Debentures

The 5.00% Debentures were listed for trading on the TSX under the symbol "AAV.DB.H" during the year-ended December 31, 2014. The following table sets forth the high and low trading prices and the aggregate trading volume of the 5.00% Debentures as reported by the TSX for the period indicated. The 5.00% Debentures were delisted from trading on the TSX on January 30, 2015.

Period	High	Low	Volume
	($)	**($)**	
2014			
January	101.00	100.51	9,110
February	101.03	100.53	22,780
March	101.20	100.76	17,040
April	101.87	101.00	2,610
May	102.85	101.50	26,830
June	105.00	102.45	100,190
July	103.00	101.50	36,610
August	101.94	101.29	11,190
September	101.94	100.71	67,950
October	100.99	100.31	40,160
November	100.49	100.10	19,580
December	100.46	99.95	10,880
2015			
January	100.18	100.02	54,790

Prior Sales

During the year ended December 31, 2014, the Corporation granted 3,777,255 stock options with a weighted average exercise price of $5.00 and granted 409,702 Performance Awards.

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTIONS ON TRANSFER

There are presently no AOG 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, 2014, 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, 2014 there were: (i) no penalties or sanctions imposed against AOG 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 AOG or its subsidiaries that would likely be considered important to a reasonable investor in making an investment decision; and (iii) no settlement agreements AOG or its subsidiaries entered into before a court relating to a securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as disclosed below, there were no material interests, direct or indirect, of directors and executive officers of AOG or its subsidiaries or nominees for director of AOG 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, 2014 or in any proposed transaction which has materially affected or would materially affect AOG or its subsidiaries.

Craig Blackwood (Chief Financial Officer) was an officer of Longview from March 4, 2010 to February 4, 2014. The officers of Longview provided services to Longview under the TSA but remained as employees of Advantage. On February 4, 2014 the Corporation and Longview announced that the TSA was formally terminated. See "*General Development of the Business – 2014*".

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 AOG is the Credit Facility, a copy of which is available at www.sedar.com. See "*General Development of the Business – Three Year History*".

INTEREST OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 *Continuous Disclosure Obligations* by us during, or related to, our most recently completed financial year other than Sproule Associates Limited, our independent engineering evaluator and PricewaterhouseCoopers LLP, our current auditors. As at the date hereof, none of the principals of Sproule Associates Limited had any registered or beneficial interests, direct or indirect, in any securities or other property of AOG or of our associates or affiliates either at the time they prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them. PricewaterhouseCoopers LLP have confirmed that they are independent in accordance with the relevant rules and related interpretation prescribed by the Institute of Chartered Accountants of Alberta and the rules of the SEC and the relevant legislation and requirements of the Public Company Accounting Oversight Board (PCAOB).

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

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 audit committee (the "**Audit Committee**") is comprised of Messrs. Paul Haggis, Stephen Balog and Grant Fagerheim. The following chart sets out the assessment of each Audit Committee member's independence, financial literacy and relevant educational background and experience supporting such financial literacy.

Name, Province and Country of Residence	Independent	Financially Literate	Relevant Education and Experience
Grant Fagerheim Alberta, Canada	Yes	Yes	Chairman, President and Chief Executive Officer of Whitecap Resources Inc., a public oil and gas company, since June, 2008. Prior thereto, Mr. Fagerheim was the President and Chief Executive Officer and a Director of Cadence Energy Inc. (formerly, Kereco Energy Ltd.), a public oil and gas company, from January 2005 to September 2008. Mr. Fagerheim received his Bachelor's degree in Education (Economics Minor) from the University of Calgary in 1983 and attended the Executive MBA at Queen's University in 1995. Mr. Fagerheim currently sits on the board of directors of PRD Energy Inc., a public oil and gas company.
Paul Haggis 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. He was a director and Chair of the Investment Committee of the Insurance Corporation of British Columbia and currently serves as an advisor to the committee. He was also Chair of the Audit Committee of C.A. Bancorp and Prime Restaurants Royalty Income Fund. Currently he is on the Board of UBC Investment Management Inc., Canadian Pacific Railway, Athabasca Oil Corporation and is Chairman of Alberta Enterprise Corp. Mr. Haggis holds a Bachelor of Arts degree from the University of Western Ontario and is certified as a Chartered Director through the Directors College at McMaster University.
Stephen Balog Alberta, Canada	Yes	Yes	Principal of Alconsult International Ltd. and President, West Butte Management Inc., private consulting companies that provide technical and business advisory services to oil and gas operators. Prior thereto, President and Chief Operating Officer and a Director of Tasman Exploration Ltd. from 2001 to June, 2007. Mr. Balog has extensive oil and gas industry experience in the management and operation of senior and junior production companies. He was a key contributor to the development and use of the Canadian Oil & Gas Evaluation Handbook as an industry standard for reserves evaluation, and

Name, Province and Country of Residence	Independent	Financially Literate	Relevant Education and Experience
			has previously served on the Petroleum Advisory Committee, Alberta Securities Commission.

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 which was originally approved by the AOG Board of Directors on April 30, 2002 and amended in April 2003, April 2004, June 2005, August 2005, October, 2005 and September, 2009:

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 IV.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:

(d) 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;

(e) 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;

(f) 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	2014	2013
Audit Fees[(1)]	$355,000	$382,000
Audit-Related Fees[(2)]	68,000	66,000
Tax Fees[(3)]	35,000	40,600
Other Fees[(4)]	42,000	-
Total	$500,000	$488,600

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 2014 Secondary Offering.

INDUSTRY CONDITIONS

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

Pricing and Marketing

Oil

In Canada, the producers of oil are entitled to negotiate sales contracts directly with oil purchasers, which results in the market determining the price of oil. Worldwide supply and demand factors primarily determine oil prices; however, prices are also influenced by regional market and transportation issues. The specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, the supply/demand balance and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB. The NEB is currently undergoing a consultation process to update the regulations governing the issuance of export licences. The updating process is necessary to meet the criteria set out in the federal *Jobs, Growth and Long-term Prosperity Act* (Canada) (the "**Prosperity Act**") which received Royal Assent on June 29, 2012. In this transitory period, the NEB has issued, and is currently following an "Interim Memorandum of Guidance concerning Oil and Gas Export Applications and Gas Import Applications" under Part VI of the *National Energy Board Act* (Canada).

Natural Gas

Alberta's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system such as the Alberta "NIT" (Nova Inventory Transfer), at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange (NGX), Intercontinental Exchange or the New York Mercantile Exchange (NYMEX) in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB.

The North American Free Trade Agreement

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

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

Royalties and Incentives

General

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

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

Alberta

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

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

Oil sands projects are also subject to Alberta's royalty regime. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1% - 9% depending on the market price of oil, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil at Cushing, Oklahoma. Rates are 1% when the market price of oil is less than or equal to $55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of 1% - 9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above $55 up to 40% when oil is priced at $120 or higher. In addition, concurrent with the implementation of The New Royalty Framework, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the new royalty regime.

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

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

In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the "**Emerging Resource and Technologies Initiative**"). Specifically:

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

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

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

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

Land Tenure

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

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

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

Production and Operation Regulations

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

Environmental Regulation

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

Federal

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

Alberta

The regulatory landscape in Alberta has undergone a transformation from multiple regulatory bodies to a single regulator for upstream oil and gas, oil sands and coal development activity. On June 17, 2013, the Alberta Energy Regulator (the "**AER**") assumed the functions and responsibilities of the former Energy Resources Conservation Board, including those found under the *Oil and Gas Conservation Act* ("**ABOGCA**"). On November 30, 2013, the AER assumed the energy related functions and responsibilities of Alberta Environment and Sustainable Resource

Development ("**AESRD**") in respect of the disposition and management of public lands under the *Public Lands Act*. On March 29, 2014, the AER assumed the energy related functions and responsibilities of AESRD in the areas of environment and water under the *Environmental Protection and Enhancement Act* and the *Water Act*, respectively. 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 the transformation to a single regulator is the creation of an enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

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

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

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("**LARP**") which came into force on September 1, 2012. The LARP is the first of seven regional plans developed under the ALUF. LARP covers a region in the northeastern corner of Alberta that is approximately 93,212 square kilometres in size. The region includes a substantial portion of the Athabasca oil sands area, which contains approximately 82% of the province's oil sands resources and much of the Cold Lake oil sands area.

LARP establishes six new conservation areas and nine new provincial recreation areas. In conservation and provincial recreation areas, conventional oil and gas companies with pre-existing tenure may continue to operate. Any new petroleum and gas tenure issued in conservation and provincial recreation areas will include a restriction that prohibits surface access. In contrast, oil sands companies' tenure has been (or will be) cancelled in conservation areas and no new oil sands tenure will be issued. While new oil sands tenure will be issued in provincial recreation areas, new and existing oil sands tenure will prohibit surface access.

In July 2014, the Government of Alberta approved the South Saskatchewan Regional Plan ("**SSRP**") which came into force on September 1, 2014. The SSRP is the second regional plan developed under the ALUF. The SSRP covers approximately 83,764 square kilometres and includes 44% of the provincial population.

The SSRP creates four new and four expanded conservation areas, and two new and six expanded provincial parks and recreational areas. Similar to LARP, the SSRP will honour existing petroleum and natural gas tenure in conservation and provincial recreational areas. However, any new petroleum and natural gas tenures sold in conservation areas, provincial parks, and recreational areas will prohibit surface access. However, oil and gas companies must minimize impacts of activities on the natural landscape, historic resources, wildlife, fish and vegetation when exploring, developing and extracting the resources. Freehold mineral rights will not be subject to this restriction.

With the implementation of the new Alberta regulatory structure under the AER, AESRD will remain responsible for development and implementation of regional plans. However, the AER will take on some responsibility for implementing regional plans in respect of energy related activities.

Liability Management Rating Programs

Alberta

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

Effective May 1, 2013, the AER implemented important changes to the AB LLR Program that resulted in a significant increase in the number of oil and gas companies in Alberta that are required to post security. Some of the important changes include:

- a 25% increase to the prescribed average reclamation cost for each individual well or facility (which will increase a licensee's deemed liabilities);

- a $7,000 increase to facility abandonment cost parameters for each well equivalent (which will increase a licensee's deemed liabilities);

- a decrease in the industry average netback from a five-year to a three-year average (which will affect the calculation of a licensee's deemed assets, as the reduction from five to three years means the average will be more sensitive to price changes); and

- a change to the present value and salvage factor, increasing to 1.0 for all active facilities from the current 0.75 for active wells and 0.50 for active facilities (which will increase a licensee's deemed liabilities).

These changes will be implemented over a three-year period. The first phase was implemented in May of 2013, the second phase was implemented in May of 2014 and the final phase will be implemented in May of 2015. The changes to the AB LLR Program stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

On July 4, 2014, the AER introduced the inactive well compliance program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under *Directive 013: Suspension Requirements for Wells* ("**Directive 013**"). The IWCP applies to all inactive wells that are noncompliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within 5 years. As of April 1, 2015, each licensee will be required to bring 20% of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with *Directive 020: Well Abandonment*.

Climate Change Regulation

Federal

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

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

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets, for application to regulated sectors on a facility-specific basis, sector-wide basis or company-by-company basis. Although the intention was for draft regulations aimed at implementing the Updated Action Plan to become binding on January 1, 2010, the only regulations being implemented are in the transportation and electricity sectors. The federal government indicates that it is taking a sector-by-sector regulatory approach to reducing GHG emissions and is working on regulations for other sectors. Representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. In June 2012, the second US-Canada Clean Energy Dialogue Action Plan was released. The plan renewed efforts to enhance bilateral collaboration on the development of clean energy technologies to reduce GHG emissions.

Alberta

As part of Alberta's 2008 Climate Change Strategy, the province committed to taking action on three themes: (a) conserving and using energy efficiently (reducing GHG emissions); (b) greening energy production; and (c) implementing carbon and capture storage.

As part of its efforts to reduce GHG emissions, Alberta introduced legislation to address GHG emissions: the *Climate Change and Emissions Management Act* (the "**CCEMA**") enacted on December 4, 2003 and amended through the *Climate Change and Emissions Management Amendment Act*, which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach and aims for a 50% reduction from 1990 emissions relative to GDP by 2020. The accompanying regulations include the *Specified Gas Emitters Regulation* ("**SGER**"), which imposes GHG limits, and the *Specified Gas Reporting Regulation*, which imposes GHG emissions reporting requirements. Alberta facilities emitting more than 100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their GHG emissions.

The SGER, effective July 1, 2007, applies to facilities emitting more than 100,000 tonnes of GHGs in 2003 or any subsequent year, and requires reductions in GHG emissions intensity (e.g. the quantity of GHG emissions per unit of production) from emissions intensity baselines established in accordance with the SGER. The SGER distinguishes between "Established Facilities" and "New Facilities". Established Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2000 or that have completed eight or more years of commercial operation. Established Facilities are required to reduce their emissions intensity by 12% of their baseline emissions intensity for 2008 and subsequent years. Generally, the baseline for an Established Facility reflects the average of emissions intensity in 2003, 2004 and 2005. New Facilities are defined as facilities that completed their first year of commercial operation on December 31, 2000, or a subsequent year, and have completed less than eight years of commercial operation, or are designated as New Facilities in accordance with the SGER. New Facilities are required to reduce their emissions intensity by 2% from their baseline in the fourth year of commercial operation, 4% of their baseline in the fifth year, 6% of their baseline in the sixth year, 8% of their baseline in the seventh year and 10% of their baseline in the eighth year. The CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA provides that regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund at a rate of $15 per tonne of CO_2 equivalent. The funds contributed by industry to the Climate Change and Emissions Management Fund will be used to drive innovation and test and implement new technologies for greening energy production. Emissions credits can also be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta.

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

RISK FACTORS

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

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

Prices, Markets and Marketing

Numerous factors beyond the Corporation's control do, and will continue to, affect the marketability and price of oil and natural gas acquired or discovered by the Corporation. The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire space 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 as well as government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect the Corporation.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions, in the United States, Canada and Europe, the actions of Organization of the Petroleum Exporting Countries ("**OPEC**"), governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply and demand of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and the Corporation's ability to access such markets. Oil prices are expected to remain volatile and may decline in the near future as a result of global excess supply due to the increased growth of shale oil production in the United States, the decline in global demand for exported crude oil commodities, and OPEC's recent decisions pertaining to the oil production of OPEC member countries, among other factors. A material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes 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 acquisition, development and exploration activities. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

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

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.

Global Financial Markets

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels, have caused significant volatility in commodity prices. These events and conditions have caused a decrease in confidence in the broader United States and global credit and financial markets and have created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and are likely to continue to impact the performance of the global economy going forward. Worldwide crude oil commodity prices are expected to remain volatile in the near future as a result of global excess supply, recent actions taken by OPEC, and ongoing global credit and liquidity concerns. This volatility may affect the Corporation's ability to obtain equity or debt financing on acceptable terms.

Exploration, Development and Production Risks

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

Project Risks

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

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling 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 supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

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

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this document are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves and the future net cash flows from such estimated reserves are based upon a number of variable factors and assumptions, such as:

- historical production from the properties;

- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures;
- marketability of oil and natural gas;
- royalty rates; and
- the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates and such variations could be material.

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

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

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

Gathering and Processing Facilities, Pipeline Systems and Rail

The Corporation delivers its products through gathering and processing facilities and pipeline systems some of which it does not own. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines, and in particular the processing facilities, 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. Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. Furthermore, 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 and it is projected to continue in this upward trend. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Corporation's business and, in turn, the Corporation's financial condition, results of operations and cash flows.

Following major accidents in Lac-Megantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Board have recommended additional regulations for railway tank cars carrying crude oil. These recommendations include, among others, the imposition of higher standards for all DOT-111 tank cars carrying crude oil and the increased auditing of shippers to ensure they properly classify hazardous materials and have adequate safety plans in place. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and add additional costs to the transportation of crude oil by rail.

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.

Substantial Capital Requirements

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

- the overall state of the capital markets;
- the Corporation's credit rating (if applicable);
- 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. 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 inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

Additional Funding Requirements

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and from time to time, the Corporation may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. There is risk that if the economy and banking industry experienced unexpected and/or prolonged deterioration, the Corporation's access to additional financing may be affected.

Because of global economic 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. 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.

Credit Facility Arrangements

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

The Corporation's lenders use the Corporation's reserves, commodity prices, applicable discount rate and other factors, to periodically determine the Corporation's borrowing base. A material decline in commodity prices could reduce the Corporation's borrowing base, reducing the funds available to the Corporation under the credit facility which could result in the requirement to repay a portion, or all, of the Corporation's bank indebtedness.

Hedging

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

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

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

Management of Growth

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

Reliance on Key Personnel

The Corporation's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have any key person 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.

Competition

The petroleum industry is competitive in all of its phases. The Corporation competes with numerous other entities in the search for, and the acquisition of, oil and natural gas properties and in the 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. 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, methods, and reliability of delivery and storage.

Hydraulic Fracturing

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

Due to recent seismic activity reported in the Fox Creek area of Alberta, the Alberta Energy Regulator has announced new 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 Alberta Energy Regulator continues to monitor seismic activity around the province and may extend these requirements to other areas of the province if necessary.

Availability of Drilling Equipment and Access

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

Seasonality

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. In addition, 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. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding decreases in the demand for the goods and services of the Corporation.

Variations in Foreign Exchange Rates and Interest Rates

World oil and natural gas prices are quoted in United States dollars. The Canadian/United States dollar exchange rate, which fluctuates over time, consequently affects the price received by Canadian producers of oil and natural gas.

Material increases in the value of the Canadian dollar relative to the United States dollar will negatively affect the Corporation's production revenues. Accordingly, Canadian/United States exchange rates could affect the future value of the Corporation's reserves as determined by independent evaluators.

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

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

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain 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 laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. See "*Industry Conditions*". The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Corporation's costs, either of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, the Corporation will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities. 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 to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, the Corporation's business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada).

Insurance

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

Third Party Credit Risk

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In 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.

Liability Management

Alberta has developed a liability management program 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 becomes defunct. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes of the ratio of the Corporation' deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted. See "*Industry Conditions*".

Tax Horizon

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

Operational Dependence

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

Title to Assets

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

Expiration of Licences and Leases

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

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation considers acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired businesses may require substantial management effort, time and resources diverting management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided 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, if disposed of, may realize less than their carrying value on the financial statements of the Corporation.

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

Climate Change

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases which may require the Corporation to comply with greenhouse gas ("**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 *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and a participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction in GHG emissions from 2005 levels by 2020. These GHG emission reduction targets are not binding, however. 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. The direct or indirect costs of compliance with these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition.

Geo-Political Risks

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

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

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights in portions of western Canada. The Corporation is not aware that any claims have been made in respect of its properties and assets; however, if a claim arose and was successful, such claim may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects

Issuance of Debt

From time to time, the Corporation may enter into transactions to acquire assets or shares of other organizations. 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.

Market Price of Common Shares

The trading price of securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. 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. 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. The price at which the Common Shares will trade cannot be accurately predicted.

Dilution

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

Conflicts of Interest

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

Dividends

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

Internal Controls

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

Cost of New Technologies

The oil industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other oil 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. 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, 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

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

Royalty Regimes

There can be no assurance that the federal government and the provincial governments of the western provinces will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of the Corporation's projects. An increase in royalties would reduce the Corporation's earnings and could make future capital investments, or the Corporation's operations, less economic. See "*Industry Conditions – Royalties and Incentives*".

Litigation

In the normal course of the Corporation's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, related to personal injuries, property damage, property tax, land rights, the environment and contract disputes. The outcome of 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.

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, the Corporation may disclose confidential information relating to the business, operations or affairs of the Corporation. Although confidentiality agreements are 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.

Income Taxes

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

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

Expansion into New Activities

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

Forward-Looking Information May Prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on the Corporation's forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risk 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*".

DISCLOSURE PURSUANT TO THE REQUIREMENTS OF THE NEW YORK STOCK EXCHANGE

As a foreign private issuer listed on the NYSE, AOG is not required to comply with most of the NYSE rules and listing standards and instead may comply with domestic Canadian requirements. AOG is, however, required to comply with the following NYSE Rules: (i) AOG 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) 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) 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. AOG 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 AOG. 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, 2014.

SCHEDULE "A"

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

Management of Advantage Oil & Gas Ltd. ("**AOG**") is responsible for the preparation and disclosure of information with respect to AOG's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014, estimated using forecast prices and costs.

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

The independent reserves evaluation committee of the board of directors of AOG has:

(a) reviewed AOG'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 independent reserves evaluation committee of the board of directors of AOG has reviewed AOG'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 independent reserves evaluation 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; and

(c) the content and filing of this report.

Because the reserves data are based on judgments 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

March 25, 2015

SCHEDULE "B"

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

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, 2014. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014, 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.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**"), prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. 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.

4. The following table sets forth the estimated 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 by us for the year ended December 31, 2014, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (County)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited (M$)	**Evaluated (M$)**	**Reviewed (M$)**	**Total (M$)**
Sproule Associates Limited	Evaluation of the P&NG Reserves of Advantage Oil & Gas Ltd.	Canada				
	As of December 31, 2014, prepared December 2014 to February 2015		Nil	2,297,158	Nil	2,297,158
Total			Nil	2,297,158	Nil	2,297,158

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

6. We have no responsibility to update the report referred to in paragraph 4 for events and circumstances occurring after its preparation date.

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

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta
February 5, 2015

Original Signed by Attila A. Szabo, P. Eng.
Attila A. Szabo, P. Eng.
Vice-President, Engineering, Canada and Director

Original Signed by Nora T. Stewart, P. Eng.
Nora T. Stewart, P. Eng.
Senior Vice-President, Canada and Director

Original Signed by Brent A. Hawkwood, C.E.T..
Brent A. Hawkwood, C.E.T.
Senior Petroleum Technologist and Partner

Original Signed by Victor Verkhogliad, P.Geol.
Victor Verkhogliad, P.Geol.
Senior Petroleum Geologist and Partner