Advantage
Oil & Gas Ltd.

ANNUAL INFORMATION FORM

YEAR ENDED DECEMBER 31, 2010

March 22, 2011

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SCHEDULES

GLOSSARY OF TERMS

Selected Defined Terms

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

"**6.50% Debentures**" means 6.50% convertible unsecured subordinated debentures of the Corporation which matured on June 30, 2010;

"**7.75% Debentures**" means 7.75% convertible unsecured subordinated debentures of the Corporation due December 1, 2011;

"**8.00% Debentures**" means 8.00% convertible unsecured subordinated debentures of the Corporation due December 31, 2011;

"**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**" means the board of directors of AOG;

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

"**Debentures**" means, collectively, the 5.00% Debentures, 6.50% Debentures, 7.75% Debentures and 8.00% Debentures;

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

"**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;

"**Trust**" means Advantage Energy Income Fund, a trust established under the laws of the Province of Alberta and dissolved effective July 9, 2009 pursuant to the Trust Conversion;

"**Trust Conversion**" means 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;

"**Trust Debentures**" means, collectively, the 6.50% Debentures, the 7.75% Debentures and the 8.00% Debentures;

"**Trust Indenture**" means the trust indenture between Computershare Trust Company of Canada and AOG made effective as of April 17, 2001, supplemented as of May 22, 2002 and amended and restated as of June 25, 2002, May 28, 2002, May 26, 2004, April 27, 2005, December 13, 2005, June 23, 2006 and December 31, 2007, as supplemented on July 9, 2009, pursuant to which the Trust was formed;

"**Trust Unit**" or "**Unit**" means a unit of the Trust, each unit representing an equal undivided beneficial interest therein;

"**Trustee**" means Computershare Trust Company of Canada as trustee under the Trust Indenture;

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

"**Unitholders**" means the holders from time to time of one or more Trust Units, as shown on the register of such holders maintained by the Trust or by the Trustee, as transfer agent of the Trust Units, on behalf of the Trust; 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;

"**Current Production**" means average daily gross production for the three month period ended December 31, 2010;

"**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, pumping equipment and wellhead assembly;

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

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

(d) provide improved recovery systems;

"**exploration costs**" means costs incurred in identifying areas that may warrant examination and 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 and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

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

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title 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 and non-operating) 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 interest (operating and non-operating) after deduction of royalties obligations, plus the entity's royalty interest in production or reserves;

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

(c) in relation to the Corporation's interest in a property, the total area in which 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;

"**Total Current Production**" means aggregate average daily gross production from the Properties for the three month period ended December 31, 2010; and

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

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

ABBREVIATIONS

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	m^3	cubic metres
MMboe	million barrels of oil equivalent	MMbtu	million British Thermal Units
boe/d	barrels of oil equivalent per day	GJ	Gigajoule
bbls/d	barrels of oil per day		

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. A boe 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.
WTI	means West Texas Intermediate.
°API	means the measure of the density or gravity of liquid petroleum products derived from a specific gravity.
psi	means pounds per square inch.

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	28.174
cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	bbls	6.293
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

The term "boe" or barrels of oil equivalent may be misleading, particularly if used in isolation. A boe 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.

YOU SHOULD NOT RELY ON FORWARD-LOOKING STATEMENTS BECAUSE THEY ARE INHERENTLY UNCERTAIN

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 the following:

- the performance characteristics of our assets;
- terms of the proposed transaction with Longview, including the timing of completion thereof and the assets to be acquired from AOG;
- oil and natural gas production levels;
- the size of the oil and natural gas reserves;
- the disposition of certain of the Corporation's assets to Longview, the consideration to be received by the Corporation and timing of receipt thereof;
- 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;
- tax horizons;
- estimated timing of capital expenditures;
- timing of development of undeveloped reserves;
- treatment under governmental regulatory regimes and tax laws; and
- capital expenditures programs.

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;
- failure to receive all required third party and regulatory approvals of the transaction with Longview;
- 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 and income trusts;
- geological, technical, drilling and processing problems and other difficulties in producing petroleum reserves; and
- the other factors discussed under "*Risk Factors*".

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 resources and reserves described can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward looking statements contained in this annual information form are expressly qualified by this cautionary statement.

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: 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 and future operating costs.

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 Generally Accepted Accounting Principles in Canada ("**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 prior to the consideration of how those activities are financed or how the results are taxed. Investors should be cautioned that these measures should not be construed as an alternative to net income, 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 asset retirement and changes in non-cash working capital. Cash netbacks are dependent on the determination of funds from operations and include the primary cash revenues and expenses on a per boe basis that comprise funds from operations.

ADVANTAGE OIL & GAS LTD.

General

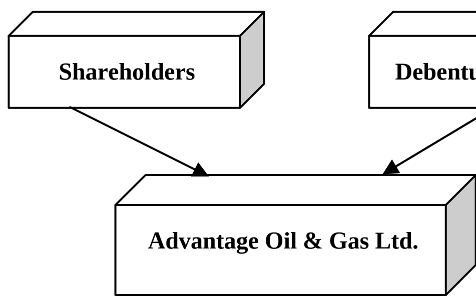
The Corporation was formed pursuant to the amalgamation of Advantage Oil & Gas Ltd., 1335703 Alberta Ltd., SET Resources Inc. and Sound ExchangeCo Ltd. under the ABCA on September 5, 2007. On July 9, 2009 the articles of the Corporation were amended in connection with the Trust Conversion to change the number of issued and outstanding Common Shares to equal the number of Trust Units outstanding immediately prior to the Trust Conversion. The Corporation is the resulting entity following the Trust Conversion with the Trust. The Trust was created under the laws of the Province of Alberta pursuant to the Trust Indenture and was dissolved in connection with the Trust Conversion.

Following the Trust Conversion, the Corporation became a reporting issuer in each of the provinces of Canada and the Common Shares were listed on the TSX and NYSE under the symbol "AAV".

The head office of AOG is located at Suite 700, 400 – 3rd Avenue S.W., Calgary, Alberta T2P 4H2 and its registered office is located at 350 – 7th Avenue S.W., Calgary, Alberta T2P 3N9.

Corporate Structure

The following diagram illustrates the organizational structure of the Corporation as at the date hereof which does not include the Corporation's subsidiaries, as the total assets and sales and operating revenues of such subsidiaries, on a combined basis, does not exceed 10% of the consolidated assets and the consolidated sales and operating revenues of the Corporation.



Advantage has a wholly owned subsidiary, Longview Oil Corp. ("**Longview**"), which filed a preliminary prospectus on March 4, 2011 for an initial public offering of common shares. Longview was created to acquire certain oil-weighted assets of the Corporation located in West Central Alberta, Southeast Saskatchewan and the Lloydminster area of Saskatchewan. See "*General Development of the Business – Recent Developments*".

GENERAL DEVELOPMENT OF THE BUSINESS

General

The Corporation is actively engaged in the business of oil and gas exploitation, development, acquisition and production in the Provinces of Alberta and Saskatchewan. AOG is a growth-oriented corporation and continues to carry on the business previously carried out by the Trust. See "*Description of our Business and Operations*" below.

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

Three Year History

2008

On November 7, 2008, Mr. Paul Haggis was appointed to the AOG Board of Directors.

On December 18, 2008, the Trust announced a reserve and operational update for our Montney natural gas play at its property in Glacier, Alberta where the Trust incurred approximately $92 million of capital expenditures in 2008 evaluating the resource potential in this area. The reserve and operational update included highlights of the Glacier property and a hedging update.

2009

On January 20, 2009, the Trust announced that the AOG Board of Directors adopted a Unitholder Rights Plan (the "**Rights Plan**") for which Unitholder approval was obtained at the Trust's annual meeting of Unitholders held on July 9, 2009. The Rights Plan was designed to provide Unitholders and the Board of Directors with adequate time to consider and evaluate any unsolicited bid made for the Trust, to provide the Board of Directors with adequate time to indentify, develop and negotiate value-enhancing alternatives, if considered appropriate, to any such unsolicited bid, to encourage the fair treatment of Unitholders in connection with any take-over bid for the Trust and to ensure that any proposed transaction is in the best interests of the Unitholders of the Trust.

On January 27, 2009, we announced the following appointments to the executive officer team of AOG: (i) Mr. Andy Mah, the former President and Chief Operating Officer, was appointed to the position of Chief Executive Officer; (ii) Mr. Kelly Drader, the former Chief Executive Officer, was appointed as President and Chief Financial Officer; (iii) Mr. Craig Blackwood, the former Director of Finance, was appointed as Vice-President, Finance; and (iv) Mr. Peter Hanrahan, the former Vice-President of Finance and Chief Financial Officer, elected to resign from such positions.

On March 18, 2009, the Trust announced that the AOG Board had unanimously approved a conversion of the Trust to a growth-oriented corporation, the Corporation. The Trust Conversion was completed on July 9, 2009. Pursuant to the Trust Conversion, Unitholders received one Common Share in the Corporation for each Trust Unit they held and the Corporation assumed all the obligations of the Trust in respect of the Trust's outstanding Trust Debentures such that, upon maturity of the Trust Debentures or such other date as communicated by the Corporation, the Trust Debentures will be satisfied with cash or the Common Shares of the Corporation in lieu of Trust Units, at the option of the Corporation. Following the completion of the Trust Conversion, the senior management and Board of Directors of the Corporation was substantially the same as the Trust, with the exception of Messrs. Bourgeois and Tourigny who retired from the Board of Directors of the Corporation.

On March 18, 2009, the Trust further announced that as another step to increase the Trust's financial flexibility and to focus on development and growth at its Glacier property, the Trust would be discontinuing the payment of cash distributions with the final cash distribution paid to Unitholders on March 16, 2009 to Unitholders of record as of February 27, 2009.

On March 18, 2009, the Trust announced that it had retained Tristone Capital Inc. to assist with the disposition of up to 11,300 boe/d of light oil and liquids rich natural gas properties (the "**Disposition of Assets**"). The net proceeds from these sales were initially used to reduce outstanding bank debt to improve the Trust's financial flexibility.

On June 15, 2009, the Trust announced that it had signed two purchase and sale agreements relating to the disposition of $252.6 million of assets. The disposition price for one package (the "**Package One Assets**") of the Sale Assets was $176 million, subject to customary adjustments. The Package One Assets were producing as of June 15, 2009 approximately 5,900 boe/d and proved plus probable reserves of the Package One Assets were estimated by Sproule to be 18.8 MMboe as of March 31, 2009. The closing of the sale of the Package One Assets occurred on July 24, 2009, with an April 1, 2009 effective date. The disposition price for the second package (the "Package Two Assets") of the Sale Assets was $76.6 million, subject to customary adjustments. The Package Two Assets were producing as of June 15, 2009 approximately 2,200 boe/d and proved plus probable reserves of the Package Two

Assets were estimated by Sproule to be 8.5 MMboe as of March 31, 2009. The closing of the sale of the Package Two Assets occurred on July 15, 2009, with an April 1, 2009 effective date.

On July 7, 2009, the Trust completed a bought deal financing through a syndicate of underwriters. Pursuant to the financing, the Trust issued 17,000,000 Trust Units at a price of $6.00 per Trust Unit for gross proceeds of $102 million. All of the net proceeds of the financing were initially used by the Trust to repay indebtedness under its credit facilities, which was available to be subsequently redrawn and applied as needed to fund AOG's capital expenditure program.

On July 8, 2009, the Trust announced its corporate capital budget for the 12 month period ending June 2010 had been set at $207 million. The budget was to focus on development of our Montney natural gas resource play at the Glacier property where Advantage was to continue to employ a phased development approach. Phase I of the development plan was achieved during Q2 2009 where production capacity was increased to approximately 25 MMcf/d and included wells, compression facilities and additional pipelines. Phase II of the development plan was undertaken from July, 2009 to July, 2010 and was designed to increase production capacity to approximately 50 MMcf/d by mid-year 2010. Phase III of the development plan was intended to increase production capacity to 100 MMcf/d by mid-year 2011.

On July 9, 2009 the Corporation announced completion of the Trust Conversion and the Corporation's Common Shares and the 6.50% Debentures, the 7.75% Debentures and the 8.00% Debentures commenced trading on the TSX and the Corporation's Common Shares commenced trading on the NYSE on July 14, 2009.

On August 13, 2009, in connection with completion of the Trust Conversion and Disposition of Assets, the Corporation's credit facilities were amended to be a $525 million facility comprised of a $20 million revolving operating loan facility and a $505 million extendible revolving credit facility (the "**Credit Facilities**"). 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 with the next redetermination anticipated to take place in June 2010. 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.

On December 7, 2009, the Corporation provided an operational update regarding its Montney drilling program at the Glacier property and highlighted its proposed development program.

On December 31, 2009 the Corporation completed the offering of $86,250,000 principal amount of 5.00% Debentures, which included $11,250,000 principal amount of 5.00% Debentures issued on exercise in full of the over-allotment option granted to the underwriters. AOG used the net proceeds of the offering to repay outstanding bank indebtedness and for general corporate purposes.

2010

On January 19, 2010, the Board of Directors of AOG approved a capital budget and updated guidance for the six month period ended June 30, 2010. Capital expenditures during the period were estimated to be approximately $110 million (80% directed to the Glacier property) and to be funded out of funds from operations.

On April 19, 2010, the Corporation announced that production from the Corporation's Glacier property exceeded 50 MMcf/d with the commissioning of Advantage’s new 100% working interest gas plant at Glacier.

On May 10, 2010, the Corporation announced that it had signed purchase and sale agreements relating to the disposition of non-core natural gas weighted assets located in South Eastern Alberta for gross cash proceeds of $67 million, subject to customary adjustments. The disposition was comprised of two separate transactions which included combined production of approximately 1,700 boe/d (80% natural gas) and proved plus probable reserves of

6.4 MMboe as at December 31, 2009. The transactions closed on May 31, 2010 and June 3, 2010 with effective dates of March 1, 2010 and April 1, 2010, respectively. The net proceeds from these dispositions were initially used to repay bank indebtedness under the Credit Facilities.

On June 14, 2010, the Board of Directors of AOG approved a capital budget and updated guidance for the twelve month period ending June 30, 2011. The capital budget is focused on increasing production at the Glacier property from 50 MMcf/d to a target of 100 MMcf/d by the second quarter of 2011. Capital expenditures during the period were estimated to be approximately $219 million (80% directed to the Glacier property) and to be funded out of funds from operations.

On June 25, 2010, the Corporation announced that its lenders had completed their review of the borrowing base of the Credit Facilities, which will remain unchanged at $525 million and continue to provide significant financial flexibility in support of future capital program requirements and general corporate purposes.

Recent Developments

Longview Transaction

Longview, a wholly owned subsidiary of the Corporation, filed a preliminary prospectus on March 4, 2011 for an initial public offering of common shares (the "**Longview Offering**"). Longview was created to acquire certain oil-weighted assets (the "**Acquired Assets**") of the Corporation located in West Central Alberta, Southeast Saskatchewan and the Lloydminster area of Saskatchewan. Concurrent with closing of the Longview Offering, Longview will purchase the Acquired Assets from AOG (the "**Longview Transaction**"), with consideration comprised of the net proceeds of the Longview Offering, common shares of Longview and proceeds of $100 million to be drawn from an independent Longview credit facility (which is anticipated to be $200 million) to be established at closing. Advantage plans to use the cash proceeds from the Longview Transaction to reduce outstanding bank indebtedness. The Longview Transaction is conditional upon customary industry conditions including the approval of the AOG Board.

Advantage will retain an equity ownership interest of approximately 68% of the common shares of Longview (approximately 63% if the over-allotment option is exercised in full). Concurrent with closing of the Longview Offering, AOG will enter into a Technical Services Agreement (the "**TSA**") with Longview. Under the TSA, AOG will provide the necessary personnel and technical services to manage Longview's business and Longview will reimburse AOG on a monthly basis for its share of administrative charges based on respective levels of production. Longview will have an independent board of directors with three initial members and the officers of Longview will be Kelly Drader (President and Chief Executive Officer), Craig Blackwood (Chief Financial Officer) and Andy Mah (Chief Operating Officer). The officers of Longview will provide services to Longview under the TSA but will remain as employees of Advantage.

See "*Statement of Reserves Data and Other Oil and Gas Information – Longview Transaction*" and "*Risk Factors*".

On March 22, 2011, the Corporation announced that its Phase III activities at Glacier are now substantially complete and production is exceeding 100 MMcf/d. An additional 100 MMcf/d (16,667 boe/d) of production capacity currently exists and additional wells will be brought on-stream as required to offset declines and maintain production.

Anticipated Changes in the Business

As at the date hereof, other than the sale of the Acquired Assets to Longview pursuant to the the Longview Transaction, we do not anticipate that any material change in our business will occur during the balance of the 2011 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, 2010 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 several 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 is actively engaged in the business of oil and gas exploration, development, acquisition and production in the provinces of Alberta and Saskatchewan.

Advantage's exploitation and development program is focused primarily 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, we also actively pursue growth opportunities through oil and gas asset acquisitions, as well as through corporate acquisitions. AOG targets acquisitions that are accretive to net asset value and that increase our reserve and production base per Common Share outstanding. Acquisitions must also meet reserve life index criteria and exhibit low risk opportunities to increase reserves and production. It is currently intended that AOG will finance acquisitions and investments through bank financing, the issuance of additional Common Shares from treasury and the issuance of subordinated convertible debentures, maintaining prudent leverage.

Reorganizations

Other than the Trust Conversion and the potential Longview Transaction, there have been no material reorganizations of the Trust or AOG and or any of our subsidiaries within the three most recently completed financial years or 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 receivership, bankruptcy 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.

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 reserves data by Sproule Associates Limited ("**Sproule**") in Form 51-101F2 are attached as Schedules "A" and "B" to this annual information form, which forms are incorporated herein by reference.

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated December 31, 2010. The effective date of the Statement is December 31, 2010 and the preparation date of the Statement is February 16, 2011.

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, 2010 contained in a report of Sproule dated February 16, 2011 (the "**Sproule Report**"). The Reserves Data summarizes our oil, NGLs and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs. The Reserves Data conforms with the requirements of NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which we believe is important to the readers of this information. AOG engaged Sproule to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of our reserves are in Canada and, specifically, in the provinces of Alberta and Saskatchewan.

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.

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

SUMMARY OF OIL AND GAS RESERVES
as of December 31, 2010
FORECAST PRICES AND COSTS

RESERVES CATEGORY	RESERVES			
	LIGHT AND MEDIUM OIL		HEAVY OIL	
	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)
PROVED				
Developed Producing	10,318.8	9,125.9	1,416.5	1,299.3
Developed Non-Producing	748.8	635.1	147.5	128.7
Undeveloped	2,794.6	2,425.7	90.0	87.4
TOTAL PROVED	13,862.1	12,186.7	1,654.0	1,515.4
PROBABLE	10,182.3	8,736.3	2,833.1	2,347.1
TOTAL PROVED PLUS PROBABLE	24,044.5	20,923.0	4,487.0	3,862.5

RESERVES CATEGORY	RESERVES			
	NATURAL GAS		NATURAL GAS LIQUIDS	
	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
PROVED				
Developed Producing	207,695	187,484	4,431.6	3,302.6
Developed Non-Producing	28,562	26,835	128.7	92.4
Undeveloped	499,783	469,190	620.8	504.7
TOTAL PROVED	736,040	683,509	5,181.1	3,899.7
PROBABLE	507,929	467,642	2,614.8	1,942.7
TOTAL PROVED PLUS PROBABLE	1,243,969	1,151,151	7,795.9	5,842.4

RESERVES CATEGORY	RESERVES	
	TOTAL OIL EQUIVALENT	
	Gross (Mboe)	Net (Mboe)
PROVED		
Developed Producing	50,782.8	44,975.2
Developed Non-Producing	5,785.3	5,328.7
Undeveloped	86,802.6	81,216.2
TOTAL PROVED	143,370.6	131,520.0
PROBABLE	100,284.9	90,966.3
TOTAL PROVED PLUS PROBABLE	243,655.5	222,486.3

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
as at December 31, 2010
FORECAST PRICES AND COSTS

	Before Income Tax Discounted at (%/year)					After Income Taxes Discounted at (%/year)					Unit Value Before Income Tax Discounted at 10%/ year(1)
RESERVES CATEGORY	**0% ($000's)**	**5% ($000's)**	**10% ($000's)**	**15% ($000's)**	**20% ($000's)**	**0% ($000's)**	**5% ($000's)**	**10% ($000's)**	**15% ($000's)**	**20% ($000's)**	**($/boe)**
PROVED											
Developed Producing	1,408,498	1,025,194	819,727	690,677	601,510	1,408,498	1,025,194	819,727	690,677	601,510	18.23
Developed Non-Producing	158,270	113,594	89,107	73,543	62,733	154,894	113,171	89,047	73,534	62,731	16.72
Undeveloped	1,653,020	909,072	525,190	304,641	168,837	1,235,861	689,308	396,962	224,605	116,436	6.47
TOTAL PROVED	3,219,789	2,047,860	1,434,024	1,068,861	833,080	2,799,252	1,827,674	1,305,736	988,816	780,677	10.90
PROBABLE	3,410,239	1,750,334	1,081,948	741,772	542,757	2,543,870	1,306,266	809,235	557,528	411,008	11.89
TOTAL PROVED PLUS PROBABLE	6,630,028	3,798,194	2,515,972	1,810,633	1,375,837	5,343,122	3,133,940	2,114,971	1,546,344	1,191,685	11.31

Note:

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

RESERVES CATEGORY	**REVENUE ($000's)**	**ROYALTIES ($000's)**	**OPERATING COSTS ($000's)**	**DEVELOP-MENT COSTS ($000's)**	**ABANDONMENT COSTS ($000's)**	**FUTURE NET REVENUE BEFORE INCOME TAXES ($000's)**	**FUTURE INCOME TAXES ($000's)**	**FUTURE NET REVENUE AFTER INCOME TAXES ($000's)**
Proved Reserves	7,042,711	639,552	1,923,984	1,185,173	74,212	3,219,789	420,536	2,799,252
Proved Plus Probable Reserves	12,625,660	1,195,580	3,053,693	1,639,721	106,636	6,630,028	1,286,907	5,343,122

Note:

(1) Alberta Drilling Royalty Credits of approximately $3.2 million for the proved plus probable case have been included as other revenue.

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2010
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)	386,668	24.88
	Heavy Oil (including solution gas and other by-products)	45,926	26.92
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	968,786	8.70
	Non-Conventional Oil and Gas Activities (Coalbed Methane)	32,645	10.96
	TOTAL	1,434,025	10.90
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	601,354	22.55
	Heavy Oil (including solution gas and other by-products)	92,521	22.39
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	1,774,164	9.47
	Non-Conventional Oil and Gas Activities (Coalbed Methane)	47,933	11.23
	TOTAL	2,515,972	11.31

Pricing Assumptions

The following tables set forth the benchmark reference prices, as at December 31, 2010, 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 of December 31, 2010
FORECAST PRICES AND COSTS

Year	WTI Cushing Oklahoma ($US/bbl)	Light Sweet Crude Oil at Edmonton 40° API ($Cdn/bbl)	Medium Crude Oil 29° API ($Cdn/bbl)	Hardisty Heavy 12° API ($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)
Forecast(3)									
2011	88.40	93.08	85.63	74.46	4.04	95.32	62.44	1.5	0.932
2012	89.14	93.85	86.34	75.08	4.66	96.11	62.95	1.5	0.932
2013	88.77	93.43	85.02	72.87	4.99	95.68	62.67	1.5	0.932
2014	88.88	93.54	84.18	71.09	6.58	95.79	62.75	1.5	0.932
2015	90.22	94.95	85.45	72.16	6.69	97.24	63.69	1.5	0.932
2016	91.57	96.38	86.74	73.25	6.80	98.71	64.65	1.5	0.932
2017	92.94	97.84	88.05	74.36	6.91	100.20	65.63	1.5	0.932
2018	94.34	99.32	89.38	75.48	7.02	101.71	66.62	1.5	0.932
2019	95.75	100.81	90.73	76.62	7.14	103.25	67.63	1.5	0.932
2020	97.19	102.34	92.10	77.78	7.26	104.81	68.65	1.5	0.932
Thereafter	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%	0.932

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.
(3) As at December 31.

Weighted average historical prices, including hedging, realized by us for the year ended December 31, 2010, were $5.45/Mcf for natural gas, $67.28/bbl for crude oil, and $48.88/bbl for NGLs.

Reconciliations of Changes in Reserves

The following table sets forth a reconciliation of the Corporation's total gross proved, gross probable and total gross proved plus probable reserves as at December 31, 2010 against such reserves as at December 31, 2009 based on forecast prices and cost assumptions.

**RECONCILIATION OF
COMPANY GROSS RESERVES
BY PRODUCT TYPE
FORECAST PRICES AND COSTS**

	Light And Medium Oil			Heavy Oil			Natural Gas Liquids		
FACTORS	WI Proved (Mbbl)	WI Probable (Mbbl)	WI Proved Plus Probable (Mbbl)	WI Proved (Mbbl)	WI Probable (Mbbl)	WI Proved Plus Probable (Mbbl)	WI Proved (Mbbl)	WI Probable (Mbbl)	WI Proved Plus Probable (Mbbl)
December 31, 2009	15,602	13,523	29,125	2,466	3,370	5,836	5,266	2,483	7,749
Extensions	345	450	795	3	1	4	42	4	46
Improved Recovery	-	-	-	-	-	-	-	-	-
Infill Drilling	176	54	230	233	(233)	0	91	47	138
Technical Revisions	(430)	(3,691)	(4,121)	(49)	8	(41)	678	125	803
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	16	9	25
Dispositions	(167)	(93)	(260)	(709)	(308)	(1,017)	(68)	(31)	(99)
Economic Factors	(93)	(61)	(154)	(8)	(5)	(13)	(67)	(22)	(89)
Production	(1,570)	-	(1,570)	(282)	-	(282)	(776)	-	(776)
December 31, 2010	13,862	10,182	24,044	1,654	2,833	4,487	5,181	2,615	7,796

	Associated and Non-Associated Gas			Natural Gas - Solution		
FACTORS	WI Proved (MMcf)	WI Probable (MMcf)	WI Proved Plus Probable (MMcf)	WI Proved (MMcf)	WI Probable (MMcf)	WI Proved Plus Probable (MMcf)
December 31, 2009	459,628	603,811	1,063,439	23,782	15,991	39,773
Extensions	140,821	66,887	207,708	881	1,157	2,038
Improved Recovery	-	-	-	-	-	-
Infill Drilling	5,322	2,050	7,372	594	(7)	587
Technical Revisions	180,548	(186,289)	(5,741)	(1,934)	(3,531)	(5,465)
Discoveries	-	-	-	-	-	-
Acquisitions	213	118	331	-	-	-
Dispositions	(18,490)	(9,172)	(27,662)	(1,268)	(518)	(1,786)
Economic Factors	(39,601)	8,665	(30,936)	(142)	(69)	(211)
Production	(31,522)	-	(31,522)	(2,928)	-	(2,928)
December 31, 2010	696,919	486,069	1,182,989	18,985	13,023	32,008

FACTORS	Coalbed Methane WI Proved (MMcf)	Coalbed Methane WI Probable (MMcf)	Coalbed Methane WI Proved Plus Probable (MMcf)	Oil Equivalent WI Proved (MBoe)	Oil Equivalent WI Probable (MBoe)	Oil Equivalent WI Proved Plus Probable (MBoe)
December 31, 2009	23,796	10,314	34,110	107,868	124,396	232,264
Extensions	42	11	53	24,014	11,797	35,811
Improved Recovery	-	-	-	-	-	-
Infill Drilling	-	-	-	1,486	207	1,693
Technical Revisions	(93)	(467)	(560)	29,953	(35,272)	(5,319)
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	51	29	80
Dispositions	-	-	-	(4,237)	(2,047)	(6,284)
Economic Factors	(989)	(1,022)	(2,011)	(6,957)	1,175	(5,782)
Production	(2,620)	-	(2,620)	(8,807)	-	(8,807)
December 31, 2010	20,136	8,836	28,972	143,371	100,285	243,656

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

Year	Light and Medium Oil (Mbbl) First Attributed	Light and Medium Oil (Mbbl) Cumulative at Year End	Heavy Oil (Mbbl) First Attributed	Heavy Oil (Mbbl) Cumulative at Year End	Natural Gas (MMcf) First Attributed	Natural Gas (MMcf) Cumulative at Year End	NGLs (Mbbl) First Attributed	NGLs (Mbbl) Cumulative at Year End
Prior thereto	3,621	3,621	297	297	52,568	52,568	928	928
2008	312	3,730	-	312	45,506	116,503	363	1,143
2009	44	2,615	-	185	166,681	297,598	7	606
2010	210	2,795	-	90	270,670	499,783	42	621

Sproule has assigned 86.8 MMboe of gross proved undeveloped reserves in the Sproule Report under forecast prices and costs, together with $1,176 million of associated undiscounted future capital expenditures. Proved undeveloped capital spending in the first two forecast years of the Sproule Report accounts for $275 million, or 23%, of the total forecast. These figures increase to $944 million or 80%, 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	8,177	8,177	2,409	2,409	87,909	87,909	1,375	1,375
2008	243	7,382	-	2,452	88,131	171,081	582	1,577
2009	23	8,221	-	2,382	391,172	546,217	3	774
2010	656	5,069	-	2,121	91,205	409,478	27	742

Sproule has assigned 76.2 MMboe of gross probable undeveloped reserves and has allocated future development capital of $451 million to all gross probable undeveloped reserves with $264 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 Current 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.

In addition, high operating costs substantially reduce our netback, which in turn reduces the amount of cash available for reinvestment in drilling opportunities. This becomes most relevant during periods of low commodity prices when profits are more significantly impacted by high costs.

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$)	Proved Plus Probable Reserves (MM$)
2011	108.6	121.3
2012	172.2	204.5
2013	359.6	397.8
2014	161.2	191.2
2015	148.3	300.4
Total: Undiscounted for all years	1,185.2	1,639.7

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 oil and gas 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.

Other Oil and Gas Information

AOG's properties are spread geographically throughout the Western Canadian Sedimentary Basin. This sedimentary basin covers a large portion of the four western Canadian provinces, with the majority of the Corporation's properties concentrated in Alberta and Saskatchewan. These properties produce from a variety of various aged geological formations and reservoirs. The Corporation operates over 85% of its properties, which allows the Corporation to control the nature and timing of the capital investments necessary to maximize the potential in developing these assets.

AOG's properties can be divided on the broad basis of commodity and of production type. Light or medium gravity oil accounts for 20% of Total Current Production and 10% of gross proved reserves, and natural gas accounts for 73% of Total Current Production and 86% of gross proved reserves.

The following property descriptions are as of February 28, 2011 unless otherwise noted and reserves quoted are as reported in the Sproule Report.

Advantage Oil and Gas Major Properties

Glacier, Alberta

The Glacier property lies along the Alberta side of the border with British Columbia between Grande Prairie, Alberta and Dawson Creek, British Columbia. The primary zones of interest are within the Triassic Montney and Doig formation siltstones. The Glacier property consists of 82.5 gross (77.75 net) sections of land with Montney interests with an average working interest of 94.25%.

In 2010, Advantage drilled and completed 33 gross (33 net) horizontal wells in the Montney and Lower Doig formations on the Glacier property. One vertical well was drilled into the underlying Belloy well and will be completed for use as an acid gas disposal well. Subsequent to year end, Advantage has drilled an additional 3 gross (3 net) horizontal Montney/Doig wells. Since the start of the horizontal drilling program in 2009, Advantage has completed 71 gross (63.4 net) horizontal wells at the Glacier property.

Advantage cases it's horizontal wells to total depth for production and uses an abras-a-jet and sand plug completion technique. On average 12 fracs per horizontal well have been placed in the wells drilled in 2010 with as many as 16 in the longer horizontal wells. The fracs are water and CO_2 fracs carrying on average 75 tonnes of sand per frac. All of the wells drilled by Advantage in 2010 and the first quarter 2011 have been completed. Test rates per well in the Upper Montney have been improving from 3.7 MMcf/d for the 8 wells in the Phase I (2008-2009) program through 7.3 MMcf/d for the 25 wells in the Phase II (2009-2010) program to 8.3 MMcf/d for the first 20 wells completed in the Phase III (2010 to March 7, 2011) program. These rates are average wellhead rates all normalized to 435 psi. Current Production of 100 MMcf/d or 16,667 boe/d represents over 50% of the Corporation's Total Current Production.

In the second quarter of 2010 Advantage expanded the capacity of its gas compression facility to 50 MMcf/d from 25 MMcf/d. Exit rate production from the gas compression facility at year end 2010 was 61 MMcf/d. Advantage was on-stream with its Phase III facility expansion to 100 MMcf/d capacity in the first quarter of 2011. Part of the 2010 expansion of Advantage's facility included the addition of amine for H_2S removal which allowed for gas to be sold directly into TransCanada's pipeline system concurrent with startup of the Phase II facility expansion. The Phase II expansion reduced operating costs from $8.25/boe to approximately $2.85/boe.

The Sproule Report assigns 577 bcf of gross proved natural gas reserves and 427 bcf of gross probable natural gas reserves to this property.

Nevis, Alberta

Nevis is an operated property consisting of approximately 44 gross (34.6 net) sections of land and is situated 60 kilometres east of Red Deer, Alberta. This property produces natural gas from numerous shallow depth horizons (400 to 800 metres) including the Horseshoe Canyon, Edmonton, and Belly River formations. Nevis is Advantage's second largest producing property with Current Production from all zones of 3,210 boe/d representing 13% of Total Current Production.

The main producing zone is the Devonian age Wabamun Formation, a light oil reservoir which also produces associated natural gas and NGLs which occur at 1,600 metres of depth. This reservoir is a high porosity, low permeability carbonate with relatively low production inflow from vertical wells. As a result, horizontal drilling technology is used to access additional inflow from the low permeability rock with current development based on four wells per section. Horizontal well laterals are on average 1,200 metres in length and the wells are completed on an open hole basis and only require an acid wash as stimulation to clean the wellbore before being placed on production. Two gross (2 net) wells were drilled and completed in the Wabamun in 2010.

The property is divided into two main pools each trapped structurally and stratigraphically with an associated updip gas cap to each pool. Crude oil quality averages 39^{o} API. Two operated facilities are utilized for processing the oil and natural gas production which is gathered from the wells through pipelines to the respective central facilities. Clean oil is trucked from the facilities and water is disposed of back into the reservoir. Associated gas is transported through pipelines to third party compression and sales. In the eastern pool, a pilot waterflood scheme has been started to evaluate the potential for enhanced recovery of these pools in order to access the large oil-in place which is not being drained through primary development.

Regulatory approval has been received to downspace 11.5 sections to allow for the drilling density to increase up to eight wells per section. Production poolings and applications are proceeding to allow for an additional 8.5 sections to be downspaced. Advantage anticipates that the increased well density will result in increased production and enhance the ultimate recovery of hydrocarbons from these reservoirs. On a downspaced basis, Advantage has identified an additional 41.6 net horizontal drilling locations. The Corporation is also studying the implementation of enhanced recovery and/or CO2 flood applications to enhance production and reserves at Nevis.

In 2008, 35 wells were drilled for Horseshoe Canyon coal bed methane ("**CBM**") with an average working interest of 78%. These wells were brought onstream at a 120 mcf/d initial average rate and have since maintained a very flat production profile. No drilling for CBM occurred in 2009 however in 2010, 3 wells were drilled and completed, primarily for land retention purposes. In 2008 the main gathering system was expanded and compression was added at two central sites along with optimization of field compression. Advantage has approximately 40 remaining CBM drilling locations under current spacing which is on the basis of 4 wells per section of land.

The Sproule Report assigns 37 bcf of gross proved natural gas reserves and 3,924 Mbbls of gross proved crude oil and NGL reserves to this property. In addition, 17.6 bcf of gross probable natural gas reserves and 2,355 Mbbls of gross probable crude oil and NGL reserves have been assigned to this property.

Southeast Saskatchewan

This area consists of a number of individual properties and lands located within the Williston Sedimentary Basin in the southeast quadrant of Saskatchewan. Existing production at the major properties comes principally from the Ordovician Red River Formation, Devonian Winnipegosis Formation as well as from the Mississippian Midale, Frobisher and Bakken Formations. Current Production from this area is approximately 1,685 boe/d and is comprised mainly of low decline, high netback, light oil with an average API gravity of 30°.

Weyburn and Steelman Area – Midale Formation Development

The Midale Formation is a Mississippian carbonate reservoir located in Southeast Saskatchewan and is one of Canada's largest light oil pools with API gravities ranging from 32° to 40°. The Midale Formation is comprised of fractured low permeability reservoirs contained within two distinct zones being the tight, high-porosity Marly zone which sits on top of the low-porosity Vuggy zone. The latter zone has a higher permeability, and is more extensively fractured vertically than the Marly zone.

Advantage holds 68,017 gross undeveloped (55,628 net) acres of lands that are prospective for drilling in the Midale Formation and represents the largest opportunity base in the Southeast Saskatchewan area. Advantage holds direct ownership of the mineral title in approximately 63% of the net acres. Advantage has identified 60 gross (47.5 net) drilling locations in the Midale Formation. The wells are low risk, typically positioned between or adjacent to existing vertical or horizontal producers. No drilling was undertaken in 2009. One (50% net) horizontal well was drilled in the Mississippian Midale Formation in 2010.

In addition there are 69,770 gross (55,933 net) acres of land that are prospective in the Bakken and Three Forks Sanish Formations. Advantage holds direct ownership of the mineral title in approximately 64% of the net acres. There has been significant industry activity surrounding these lands targeting light oil resource plays. Drilling potential will be evaluated in these formations as information from surrounding industry activity comes into the public domain.

The Sproule Report contains 51 gross (46 net) locations in various zones in the Weyburn and Steelman areas. In addition Advantage has identified 53 gross (41.5 net) Midale horizontal drilling locations where no reserves have been assigned.

The Sproule Report assigns 4,012 Mbbls of gross proved crude oil and NGL reserves in southeast Saskatchewan. In addition, 2,734 Mbbls of gross probable crude oil and NGL reserves have been assigned to this area.

Wapella, Saskatchewan

The Wapella property is located 200 kilometres east of Regina, Saskatchewan with Current Production of approximately 527 boe/d of 25º API gravity oil with an average working interest of 90%. Production is derived from the Cretaceous and Jurassic-age Shaunavon and Gravelbourg sandstone reservoirs located at a depth of 800 metres.

Additional infill drilling and stepouts have been identified in and around the existing production from Shaunavon and Gravelbourg sand reservoirs. The Wapella property includes 18,793 gross (18,253 net) acres of undeveloped lands that are prospective in the Bakken Formation. Advantage holds direct ownership of the mineral title in approximately 82% of the net acres. Significant exploration potential exists on the undeveloped land base and recent activity for Bakken target, to the east of Wapella, suggest that favourable geological potential in this horizon could extend westward onto Advantage lands. The Sproule Report contains 40 gross (39 net) locations in the Wapella area.

The Sproule Report assigns 2,345 Mbbls of gross proved crude oil and NGL reserves in Wapella. In addition, 1,576 Mbbls of gross probable crude oil and NGL reserves have been assigned to this area.

Lloydminster, Saskatchewan

These properties lie east of the Saskatchewan/Alberta border within the Lloydminster heavy oil producing area. Current Production from these properties of approximately 572 boe/d is derived primarily from the Cretaceous

Sparky and Waseca Formations and also from the Rex, Cummings and Dina Formations. Crude oil gravities in these properties average 20º API and are all being produced conventionally at this time.

Eyehill, Saskatchewan

The Eyehill property (100% working interest) consists of 21 oil wells with Current Production of 293 boe/d. Oil production is 20º API from a Sparky Formation sand reservoir in which oil is trapped updip and laterally against shale filled channels. The Sparky oil pool is under waterflood pressure maintenance from five injection wells and is showing positive production response to this injection.

In 2010, Advantage drilled 4 wells of which 3 were completed as Sparky oil wells and the fourth was completed as a future service well for use either as water source and/or fuel gas supply. Subsequent to year end 2010 Advantage has drilled and cased three additional wells for Sparky oil production. This pool is currently spaced at two wells per 40 acres. On this basis up to 17 locations remain further to existing drilled wells. Up to 4 wells would be required to be converted to water injectors to accommodate this additional drilling with appropriate pressure maintenance.

Lashburn, Saskatchewan

At Lashburn, Advantage holds a 60% working interest. Two thick Waseca channels are present as identified in vertical wells and on 3D seismic with Current Production of approximately 236 boe/d of 21º API oil. Similar Waseca channels are being developed immediately south of the property by a major oil company with SAGD (steam assisted gravity drainage) technology which could be utilized at the Lashburn property. As an alternative, this property may be developed through a combination of vertical and horizontal drilling to increase production and enhance reserves. It is possible to initially cold-produce wells conventionally in the channel. Two older vertical wells (now suspended) have produced 280 Mbbls and 140 Mbbls of oil respectively. There is room for up to 5 horizontal locations which could be initially produced conventionally. Additional horizontals would ultimately be required for a SAGD development. No drilling occurred on this property in 2010 however drilling locations are being evaluated for 2011.

The Sproule Report assigns 1,194 Mbbls of gross proved crude oil and NGL reserves to the properties in the Lloydminster area. In addition, 2,659 Mbbls of gross probable crude oil and NGL reserves have been assigned to this area.

Sunset, Alberta

This property consists of three pools all of which are producing from Triassic age Montney Formation reservoirs and lies approximately 100 kilometres east of the City of Grande Prairie. Current Production from the three main pools in the Sunset area is 753 boe/d.

Sunset "A"

Current Production of 406 boe/d consists of 29º API crude oil from the Montney Formation which is encountered at 1,450 metres of depth. In this area, the Montney is a conventional tight fine grained sandstone reservoir in which crude oil has been trapped stratigraphically against cap rock overlying the updip subcrop unit of the reservoir. The reservoir has an underlying water leg which provides partial pressure support. Advantage has a 70% working interest, and operates the Sunset Triassic "A" Unit. The field is currently developed with vertical wells drilled mainly on 40 acre spacing from central production pads. There is a 40 year production history with stable well performance and low decline.

Infill drilling to 40 acre spacing in the pool commenced in 2005 and since that time 24 new oil wells and three additional injector wells have been added to the pool. In the center of the field, drilling has been successfully downspaced to 20 acre spacing units. A waterflood scheme was initiated in 2006 and expansion of the water injection system is ongoing. Once completed and re-pressurization of the reservoir has progressed sufficiently, further infill drilling will proceed to capture additional oil reserves. In the Sunset "A" area Sproule has assigned Montney oil reserves to 12 gross (8.41 net) probable undeveloped vertical drilling locations.

Sunset "B"

Current Production from this Montney reservoir is approximately 219 boe/d of liquids rich natural gas. Advantage has a 100% interest in this pool and owns 100% of a sour gas processing plant and gathering system with throughput capacity of 12 MMcf/d. Associated gas from Sunset "A" and from Valleyview is gathered and processed through this facility. In the Sunset "B" area, Sproule has assigned Montney gas reserves to 6 gross (5.99 net) proved undeveloped vertical drilling locations and 12 gross (12.0 net) probable undeveloped vertical drilling locations.

Valleyview

This Montney gas pool has Current Production of 127 boe/d and is connected to the Sunset "B" gas processing plant by a 12 kilometre pipeline with Advantage holding a 93% average working interest in the pool. In the Valleyview area, Sproule has assigned Montney gas reserves to 1 gross (1.0 net) proved undeveloped vertical drilling location, and to 3 gross (3.0 net) probable undeveloped vertical drilling locations.

The Sproule Report assigns 5.6 bcf of gross proved natural gas reserves and 1,014 Mbbls of gross proved crude oil and NGL reserves to Sunset/Valleyview. In addition, 9.2 bcf of gross probable natural gas reserves and 1,511 Mbbls of gross probable crude oil and NGL reserves have been assigned to these properties.

Duvernay Resource Play

Advantage has purchased at crown landsale a 100% interest in 78,750 gross acres (123 net sections) of exploratory rights in and along the Sunset corridor, which are prospective for development in the Upper Devonian Duvernay Formation shales. The corporation believes that the Duvernay lands are located within the oil generating window in this area and Advantage will continue to review and analyze this target to determine future exploratory activity. Advantage's ownership of oil and natural gas facilities in this area would be available to provide immediate processing capacity should development proceed.

Southern Alberta

Lookout Butte, Alberta

The Lookout Butte property is located approximately 90 kilometres southwest of Lethbridge, Alberta. Production occurs primarily from the Mississippian Rundle Formation where natural gas has been trapped in a foothills overthrust structure in front of Waterton Park. We have a 100% working interest in the Rundle gas production. Production began in 1963 and production decline is low at approximately 12% per year. A well drilled in 2004 in the southern portion of the pool when shut in exhibits significant pressure recharge from undrained reserves beneath adjacent Waterton and Glacier National parks. The property includes a 100% operated working interest plant and associated gas gathering system which dehydrates the gas before final processing at Shell's Waterton gas plant. Current Production from this field is 1,100 boe/d.

The Sproule Report assigns 27.1 bcf of gross proved natural gas reserves and 1,390 Mbbls of gross proved crude oil and NGL reserves to Lookout Butte. In addition, 11.2 bcf of gross probable natural gas reserves and 582 Mbbls of gross probable crude oil and NGL reserves have been assigned to this property.

Medicine Hat, Alberta

The Medicine Hat property lies 20 kilometres northeast of the City of Medicine Hat in the heart of the south-eastern shallow gas area. We have a 100% working interest in 24 sections of land from where Current Production of 5.1 MMcf/d is taken from all of the main shallow gas producing formations including the Medicine Hat "A", "C" and "D" sands, as well as both the Upper and Lower Milk River sands. These sands occur at approximately 500 metres of depth and typical of shallow gas, these sands are resource plays which require a large number of wells to extract the very large in place reserves at relatively low per well production rates. As a result, they have a long production life (long reserve life index or "**RLI**"). These reservoirs consist of low permeability strata, requiring fracture stimulation to enhance and induce productivity. The wells are gathered by an extensive network of low pressure pipelines which feed into large central gas compression facilities. This property has been downspaced and co-mingled to allow for multiple gas wells per section from multiple producing horizons per well bore.

When the property was acquired in January 2002 there were 115 wells producing approximately 5.2 MMcf/d of natural gas. From January 2002 to December 2005, 320 new wells were added. There has been no drilling since; however, a regular program of well clean outs keeps these wells optimized.

The Sproule Report assigns 28 bcf of gross proved natural gas reserves to the Medicine Hat property. In addition, 12.1 bcf of gross probable natural gas reserves have been assigned to this property.

West Central Alberta

Westerose, Alberta

The Westerose property is located approximately 60 kilometres southwest of Edmonton, Alberta. Westerose is an oil and gas property with production from various Cretaceous reservoirs but produces principally from several pools associated with the erosional subcrop edge of the Mississippian, Banff Formation. Current Production from all zones at the greater Westerose area is 971 boe/d.

The Westerose Banff "C" Unit (52% unit interest and operator) produces 24^{o} API gravity crude oil which is trapped stratigraphically along the erosional subcrop edge of the Mississippian Banff Formation. The reservoir in the Banff Formation is a dolomitized carbonate which occurs at a depth of 1,800 metres. The Westerose Banff "C" Unit is currently developed on 40 acre spacing with four water injection wells and Current Production is approximately 170 boe/d. This reservoir is currently under an active waterflood pressure maintenance scheme which commenced in 2003 and production is responding positively to injection. Additional producing and injection wells are being evaluated and will be added as required to increase oil recovery. In the Westerose Banff "C" Unit, Sproule assigned probable undeveloped reserves to 15 gross (7.8 net) vertical oil well locations.

Cardium Properties

The Cardium Formation properties lie in the west central Alberta basin primarily between Townships 38 and 48, Ranges 2 to 11W5. These properties consist of a variety of lands with working interests ranging between 8% and 100% with an average working interest of 32%. Most of the properties are non-operated with the exception of the Pembina Rose Creek Cardium Unit, which is an operated Cardium producing property consisting of 1,600 acres of 100% unit interest. In total, Advantage has 34,155 gross (10,907 net) acres of Cardium rights in this area with Current Production of approximately 155 boe/d. This acreage is exclusive of a 1.5% working interest in the North Pembina Cardium Unit Number 1. In the Westerose area, Sproule has assigned Cardium oil reserves to five gross (0.07 net) proved undeveloped horizontal drilling locations within the North Pembina Cardium Unit. Advantage has identified 9 gross (4.2 net) Cardium horizontal oil drilling locations and 1 gross (1.0 net) Notikewin natural gas drilling location.

Pembina Rose Creek Cardium Unit

Advantage has a 100% unit interest in and will operate this 1,600 acre Cardium Formation unit which has current Production of approximately 100 boe/d. The Cardium Formation in this unit consists of up to seven metres of net pay located within the southern boundary of the main Pembina field producing 36° API oil. The updip half of the property is overlain by one metre of highly permeable conglomerate. The unit has 15 active wells of which four are injecting water as pressure maintenance into the property. This property represents an opportunity for the application of multi-stage frac horizontal drilling in the Cardium trend. In the Pembina Rose Creek Cardium Unit Sproule assigned 3 gross (3.0 net) proved undeveloped horizontal drilling locations and 2 gross (2.0 net) probable undeveloped horizontal drilling locations.

The Sproule Report assigns 6.6 bcf of gross proved natural gas reserves and 2,526 Mbbls of gross proved crude oil and NGL reserves to the entire Westerose area . In addition, 2.2 bcf of gross probable natural gas reserves and 1,481 Mbbls of of gross probable crude oil and NGL reserves have been assigned to the entire Westerose area.

Chip Lake, Alberta

The Chip Lake property is located 125 kilometres west of Edmonton, Alberta. Advantage holds a 100% working interest in seven sections of land with Current Production of approximately 242 boe/d from the Rock Creek Formation. The field consists of 12 producing vertical oil wells, three water injection wells and a central oil processing battery and water disposal facility. Associated natural gas is compressed and sold through third party facilities and clean oil is trucked for sale. The Rock Creek Formation is a conventional sandstone reservoir in which 40^o API oil is trapped by an updip shale plug channel which truncates the reservoir which occurs at a depth of 1,850 metres. Pay thickness is in excess of eight metres along the axis of the reservoir and it is there and along the updip margin that infill drilling, potentially with a combination of vertical and horizontal wells, is targeted after water injection has re-pressured this area of the pool. The water injection scheme is currently being optimized and regulatory and spacing work is proceeding to allow for additional wells or conversion of existing wells into water injectors. In the Chip Lake area, Sproule has assigned Rock Creek oil reserves to five gross (5.0 net) probable undeveloped vertical drilling locations.

The Sproule Report assigns 1.6 bcf of gross proved natural gas reserves and 594 Mbbls of gross proved crude oil and NGL reserves to the Chip Lake property. In addition, 1.8 bcf of gross probable natural gas reserves and 680 Mbbls of gross probable crude oil and NGL reserves have been assigned to this property.

Willesden Green (Open Lake), Alberta

The Willesden Green property is located approximately 35 kilometres north of the Town of Rocky Mountain House. There are two principle areas in this property. The northern block produces from the Jurassic Rock Creek gas play on the east side of the property and the Cretaceous Ostracode/Glauconite oil on the north side of the property. The Rock Creek is a mixed lithology reservoir in which liquids rich gas is trapped stratigraphically in individual lenses of sand. 3D seismic is used to explore for this porosity and a number of future targets have been identified. The Ostracode is developed in a linear sand bar and produces 39^o API oil. This pool is being evaluated for potential water injection pressure maintenance. The southern block produces oil from the Cretaceous Second White Specks and Viking Formations as well as natural gas from the Glauconite Formation. Additional drilling targeting both the Second White Specks and Glauconite is being evaluated.

The Sproule Report assigns 5.8 bcf of gross proved natural gas reserves and 739 Mbbls of gross proved crude oil and NGL reserves to the Willesden Green property. In addition, 2.4 bcf of gross probable natural gas reserves and 305 Mbbls of gross probable crude oil and NGL reserves have been assigned to this property.

Brazeau -Ferrier, Alberta

The Brazeau-Ferrier area is located between 50 and 80 kilometres west of the town of Drayton Valley. The property produces sour light oil and natural gas from Devonian aged Nisku pinnacle reefs. The majority of the production is from a non-operated 50% working interest in the Nisku C, D and E pools. Major facility interests include a 25.7% working interest in the West Pembina Sour Gas Plant. Additional gas production occurs from several non-operated Rock Creek, Basal Quartz and Notikewin pools.

In the southern part of this area Advantage has acquired 6.75 sections (100% net) for Cretaceous Belly River and Notikewin Formation natural gas. 3D seismic has been acquired and locations are being evaluated as vertical drill targets in the Belly River. The acreage is being reviewed for the potential to drill a horizontal multi-stage frac well in the Notikewin Formation.

The Sproule Report assigns 7.4 bcf of gross proved natural gas reserves and 462 Mbbls of gross proved crude oil and NGL reserves to the Brazeau River area. In addition, 3.3 bcf of gross probable natural gas reserves and 285 Mbbls of gross probable crude oil and NGL reserves have been assigned to this area.

Oil and Gas Wells

The following table sets forth the number and status of wells as at December 31, 2010 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	506	322	81	56	1,423	947	368	274
Saskatchewan	377	312	55	43	72	4	5	2
Total	883	634	136	99	1,495	951	373	276

Note:

(1) Excluding minor interest in the following units (less than 5% working interest): Steelman Unit No. 3, Carrot Creek Cardium K Unit No. 1, Delburne Gas Unit, Nevis Unit No. 1, Bonnie Glen D-3A Gas Cap Unit, Turner Valley Unit No. 5, Sunchild Gas Unit No. 1, North Pembina Cardium Unit and Kakwa Cardium A Unit. Injection Wells are categorized as Non-Producing Oil Wells.

Properties with no Attributed Reserves

The following table sets out our developed and undeveloped land holdings as at December 31, 2010.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	715,890	344,705	408,426	215,332	1,124,316	560,037
Saskatchewan	56,220	37,541	126,485	90,392	182,705	127,933
Total	772,110	382,246	534,911	305,724	1,307,021	687,970

In the year ended December 31, 2010, rights to explore, develop and exploit 34,963 net acres of undeveloped land expired. We expect that rights to explore, develop and exploit 23,367 net acres of our undeveloped land holdings will expire by December 31, 2011. The land expirations do not consider our 2011 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.

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.

We have implemented a hedging policy to use costless collars and fixed price swaps to hedge up to 60% of our gross production in the first two years and up to 50% of our gross production in the third year. These hedging activities could expose us to losses or gains. To the extent that we engage in risk management activities related to commodity prices, we will be subject to credit risk associated with the parties with which we contract. This credit risk will be mitigated by entering into contracts with only stable and creditworthy parties and through the frequent review of our exposure to these entities.

Overall, approximately 25% of our net gas production is now hedged for the 2011 calendar year at a floor of $6.30/mcf. For the first quarter of 2011, we have secured approximately 34% of our net gas production at a floor of $6.43/mcf. We have also hedged approximately 34% of our 2011 net crude production at an average floor price of Cdn$88.90/bbl. For the first quarter of 2011, we have secured approximately 41% of our net oil production at a floor of Cdn$84.42/bbl.

Advantage has the following derivatives in place:

Description of Derivative	Term	Volume	Average Price
Natural gas - AECO			
Fixed price	April 2010 to January 2011	18,956 mcf/d	Cdn $7.25/mcf
Fixed price	January 2011 to December 2011	9,478 mcf/d	Cdn $6.24/mcf
Fixed price	January 2011 to December 2011	9,478 mcf/d	Cdn $6.24/mcf
Fixed price	January 2011 to December 2011	9,478 mcf/d	Cdn $6.26/mcf
Crude oil – WTI			
Fixed price	April 2010 to January 2011	2,000 bbls/d	Cdn $69.50/bbl
Fixed price	January 2011 to December 2011	1,500 bbls/d	Cdn $91.05/bbl

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 base 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 1,960 net producing and non-producing wells and 783 net abandoned wells. The approximate net cost to abandon and reclaim all wells and facilities, discounted at 10%, totals $34.1 million ($320.0 million undiscounted), of which approximately $9.2 million are included in the estimate of future net revenue ($75.7 million undiscounted). Abandonment and reclamation costs undiscounted and expected to be paid over the next three years totals $11.6 million.

Tax Horizon

In 2010, 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 2017.

Capital Expenditures

The following tables summarize capital expenditures (including capitalized general and administrative expenses) related to our activities for the year ended December 31, 2010:

Capital Expenditures ($ thousands)	2010
Land and seismic	4,309
Drilling, completions and workovers	169,814
Well equipping and facilities	48,782
Other	403
	223,308
Property Acquisition	-
Property dispositions	(69,676)
Total capital expenditures	153,632

The total capital expenditures for the year ended December 31, 2010 include approximately $0.3 million related to exploration activities.

Exploration and Development Activities

The following table sets forth the gross and net wells in which we participated during the year ended December 31, 2010:

	Exploratory		Development		Total	
	Gross	Net	Gross	Net	Gross	Net
Oil wells	0	0	20.0	9.8	20.0	9.8
Gas wells	0	0	39.0	36.7	39.0	36.7
Service wells	0	0	3.0	2.7	3.0	2.7
Dry holes	1.0	1.0	0	0	1.0	1.0
Total	1.0	1.0	62.0	49.2	63.0	50.2

Subject to, among other things, the availability of drilling rigs and weather that permits access to drill sites, in the first six months of 2011, we plan to drill, complete and tie-in 14 net wells.

We estimate capital expenditures of $70 to $80 million for the first six months of 2011 to execute our capital programs. The primary components of our programs are described under the heading "*Other Oil and Gas information – Oil and Natural Gas Properties*".

Production Estimates

The following table sets out the volume of our production estimated for the year ended December 31, 2011 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	3,557	3,049	590	512	93,992	83,493	1,586	1,172	21,398	18,649
Proved Developed Non-Producing	92	77	18	15	11,912	11,299	14	12	2,109	1,987
Proved Undeveloped	217	177	15	12	16,918	15,981	41	34	3,093	2,887
Total Proved	3,866	3,303	623	539	122,822	110,773	1,641	1,218	26,600	23,523
Total Probable	368	325	40	29	14,940	13,362	85	68	2,983	2,649
Total Proved Plus Probable	4,234	3,628	663	568	137,762	124,135	1,726	1,286	29,583	26,172

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 2010				Year Ended
	Mar. 31	June 30	Sept. 30	Dec. 31	Dec. 31, 2010
Average Daily Production[1]					
Crude Oil (bbls/d)	5,511	5,231	4,686	4,886	5,076
Gas (Mcf/d)	87,346	107,821	104,714	106,125	101,562
NGLs (bbls/d)	2,464	2,164	2,149	1,734	2,126
Combined (boe/d)	22,533	25,365	24,287	24,308	24,129
Average Net Production Prices Received[2]					
Crude Oil ($/bbl)	74.97	70.54	70.75	74.76	72.80
Gas ($/Mcf)	5.25	3.81	3.51	3.49	3.95
NGLs ($/bbl)	49.91	50.45	42.41	53.50	48.88
Combined ($/boe)	44.16	35.03	32.54	34.08	36.26

	Quarter Ended 2010				Year Ended
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**Dec. 31, 2010**
Gain/(Loss) on Derivatives					
Crude Oil ($/bbl)	(6.96)	(4.04)	(4.12)	(6.85)	(5.52)
Gas ($/Mcf)	1.62	1.77	1.29	1.32	1.50
Combined ($/boe)	4.55	6.72	4.76	4.38	5.13
Royalties Paid					
Crude Oil ($/bbl)	13.63	13.91	12.47	12.51	13.16
Gas ($/Mcf)	0.39	0.26	0.23	0.18	0.26
NGLs ($/bbl)	13.63	15.55	13.31	11.84	13.67
Combined ($/boe)	6.34	5.28	4.60	4.16	5.07
Operating Expenses(3)(4)					
Crude oil ($/bbl)	14.21	17.42	18.04	18.44	16.95
Natural gas ($/Mcf)	1.76	1.46	1.37	1.41	1.49
NGLs ($/bbl)	8.12	9.91	9.19	10.75	9.39
Combined ($/boe)	11.20	10.64	10.21	10.64	10.66
Netback Received(5)					
Crude Oil ($/bbl)	40.17	35.17	36.12	36.96	37.17
Gas ($/Mcf)	4.72	3.86	3.20	3.22	3.70
NGLs ($/bbl)	28.16	24.99	19.91	30.91	25.82
Combined ($/boe)	31.17	25.83	22.49	23.66	25.66

Notes:

(1) Before deduction of royalties.
(2) Production prices are net of costs to transport the product to market.
(3) This figure includes all field operating expenses.
(4) 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 well by well basis based upon the relative volume of production of crude oil and NGLs and natural gas.
(5) Information in respect of netbacks received for crude oil & 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 (4) above.

The following table indicates our approximate average daily production from our important fields for the quarter ended December 31, 2010:

Properties	**Natural Gas (Mcf/d)**	**Crude Oil & NGLs (bbls/d)**	**Total (boe/d)**
Glacier	53,265	32	8,910
Nevis	5,509	1,183	2,101
Red Deer	10,378	187	1,916
Willesden Green	3,914	488	1,140
Lookout Butte	5,136	256	1,112
Medicine Hat	6,505	-	1,084
Westerose	2,554	574	999
Brazeau/Ferrier	3,262	192	735
Wainwright	3,155	5	531
Eastern Alberta	2,060	1	344
Major Properties	95,738	2,918	18,872
Other	10,387	3,702	5,436
Total	106,125	6,620	24,308

Future Commitments

We have committed to certain payments over the next five years, as follows:

($ millions)	**2011**	**2012**	**2013**	**2014**	**2015**
Building leases	3.5	3.4	2.5	1.4	-
Capital leases	0.8	-	-	-	-
Pipeline/transportation	8.3	8.4	8.1	7.3	2.1
Bank indebtedness[(1)]	-	290.7	-	-	-
Convertible debentures[(2)]	62.3	-	-	-	86.2

Notes:

(1) The Corporation's bank indebtedness does not have specific maturity dates. It is governed by a credit facility agreement with a syndicate of financial institutions. Under the terms of the agreement, the Credit Facilities are reviewed annually, with the next review scheduled in June 2011. The Credit Facility is revolving, and is extendible at each annual review for a further 364 day period at the option of the syndicate. If not extended, the Credit Facility is converted at that time into a one-year term facility, with the principal payable at the end of such one-year term.

(2) As at December 31, 2010, AOG had $148.5 million Debentures outstanding. Each series of Debentures are convertible to Common Shares based on an established conversion price. All remaining obligations related to Debentures can be settled through the payment of cash or issuance of Common Shares at AOG's option.

Longview Transaction

On March 7, 2011 Advantage announced that Longview, a wholly owned subsidiary of the Corporation, filed a preliminary prospectus on March 4, 2011 for the Longview Offering, which is targeted to raise gross proceeds of $150 million prior to an over-allotment option of up to 15% of the base offering size, exercisable 30 days following the closing of the Longview Offering. The closing of the Longview Offering is expected to occur in April, 2011.

Longview was created to acquire the Acquired Assets located in West Central Alberta, Southeast Saskatchewan and the Lloydminster area of Saskatchewan with Current Production of 6,220 boe/d (74% oil and NGLs). As at December 31, 2010, the Acquired Assets had proved reserves of 20.1 mmboe (17.4 mmboe net), proved plus probable reserves of 36.9 mmboe (31.8 mmboe net) and a net present value of future net revenue for proved plus probable reserves discounted at 10% of $669.7 million before tax ($567.9 million after tax), based on a report prepared by Sproule & Associates Limited on the Acquired Assets for Advantage and Longview with an effective date of December 31, 2010. Advantage anticipates that the non-controlling interest in reserves attributable to the Acquired Assets will be approximately 32% (approximately 37% if the over-allotment option is exercised in full).

Concurrent with closing of the Longview Offering, Longview will purchase the Acquired Assets from Advantage, with consideration comprised of the net proceeds of the Longview Offering, common shares of Longview and proceeds of $100 million to be drawn from an independent Longview credit facility (which is anticipated to be $200 million) to be established at closing. Advantage plans to use the cash proceeds from the Longview Transaction to reduce outstanding bank indebtedness. The Longview Transaction is conditional upon customary industry conditions including the approval of the AOG Board.

Longview's business strategy is to provide shareholders with attractive long term returns that combine both growth and yield by exploiting the Acquired Assets in a financially disciplined manner, acquiring additional long-life oil and gas assets of a similar nature and through the payment of a monthly dividend. Advantage will retain an equity ownership interest of approximately 68% of the common shares of Longview (approximately 63% if the over-allotment option is exercised in full). Concurrent with closing of the Longview Offering, Advantage will enter into the TSA with Longview. Under the TSA, Advantage will provide the necessary personnel and technical services to manage Longview's business and Longview will reimburse Advantage on a monthly basis for its share of administrative charges based on respective levels of production. See "*Recent Developments – Longview Transaction*".

Marketing

Our crude oil and natural gas production is primarily sold through marketing companies at current market prices. Crude oil contracts are generally for less than a year and are cancellable on 30 days notice and natural gas contracts are generally for one year and are cancellable on 60 days notice. Approximately 3.5% of our natural gas production is sold to aggregators who accumulate production from various producers and market the gas on behalf of the group. Such contracts are reserve specific and continue for the life of production from the specified reserves.

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.

Renegotiation or Termination of Contracts

As at the date hereof, we do not anticipate that any aspect of our business will be materially affected in the remainder of 2011 by the renegotiation or termination of contracts or subcontracts.

Environmental Considerations

We are pro-active in our approach to environmental concerns. Procedures are in place to ensure that the utmost care is taken in the day-to-day management of our oil and gas properties. All 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 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.

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.

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

AOG participates in the Environment, Health and Safety Stewardship Program developed by the Canadian Association of Petroleum Producers. Participation requires commitment to continuous improvement in the environment, health and safety management practices including sound planning and implementation, open communication and measured performance against our peers.

Competitive Conditions

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.

Human Resources

As at December 31, 2010, we employed 128 full-time employees, 101 of which are located in the head office and 27 of which are located in the field. We also employed 19 consultants in the head office.

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 proposed directors and officers of AOG, together with their principal occupations during the last five years. The directors of AOG shall hold office until the next annual meeting of shareholders or until their respective successors have been duly elected or appointed.

Name, Province and Country of Residence	Position Held and Period Served as a Director or Officer[4][5]	Principal Occupations During Past Five Years
Kelly I. Drader Alberta, Canada	President and Chief Financial Officer since January 27, 2009 and Director since May 24, 2001	President and Chief Financial Officer of AOG since January 27, 2009. Chief Executive Officer of AOG from May 24, 2001 to January 27, 2009. President of AIM from March 2001 to June 2006. Prior thereto, Senior Vice President (1997-2001) and Vice President, Finance and Chief Financial Officer (1990-1997) of EnerPlus Group of Companies, which companies specialize in the management of oil and gas income funds and royalty trusts.
John A. Howard [2][3][7] Alberta, Canada	Director since June 23, 2006	President of Lunar Enterprises Corp., a private holding company.
Andy J. Mah Alberta, Canada	Chief Executive Officer since January 27, 2009 and a Director since June 23, 2006	Chief Executive Officer since January 27, 2009. President and Chief Operating Officer from June 23, 2006 to January 27, 2009. Prior thereto, President of Ketch Resources Ltd. since October 2005. Chief Operating Officer of Ketch Resources Ltd. from January 2005 to September 2005. Prior thereto, Executive Officer and Vice President, Engineering and Operations of Northrock Resources Ltd. from August 1998 to January 2005.
Ronald A. McIntosh[1][3][8] Alberta, Canada	Director since September 25, 1998[6]	Chairman of North American Energy Partners Inc., a publicly traded corporation and a director of Fortress Energy Inc.
Stephen E. Balog[1][3] Alberta, Canada	Director since August 16, 2007	President, West Butte Management Inc., a private oil and gas consulting company. Prior thereto, President & Chief Operating Officer and a Director of Tasman Exploration Ltd. from 2001 to June, 2007.
Carol D. Pennycook[1][2] Ontario, Canada	Director since May 26, 2004	Partner at the Toronto office of Davies Ward Phillips & Vineberg, LLP, a national law firm.
Steven Sharpe Ontario, Canada	Director since May 24, 2001 and Non-Executive Chairman since May 26, 2004	Managing Director, The EmBeSa Corporation and Chairman and Chief Executive Officer of Prime Restaurants Royalty Income Fund. Until July, 2009, Senior Advisor to Blair Franklin Capital Partners, Inc., a Toronto-based investment bank which he co-founded in May, 2003. Prior to that, Mr. Sharpe was Managing Partner of Blair Franklin, from its inception. Before then, he was Managing Director of The EBS Corporation, a management and strategic consulting firm. Prior to EBS, Mr. Sharpe was Executive Vice President of The Kroll-O'Gara Company, New York.

Name, Province and Country of Residence	Position Held and Period Served as a Director or Officer(4)(5)	Principal Occupations During Past Five Years
Sheila O'Brien(2) (3) Alberta, Canada	Director since March 21, 2007	From April 2004, President of Belvedere Investments and Corporate Director; from July 1998 to April 2004, Senior Vice President, Human Resources, Public Affairs, Investor and Government Relations with Nova Chemicals Corporation. Among her other accomplishments, Ms. O'Brien was designated as Member, Order of Canada in 1999.
Paul Haggis (1) 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 and currently serves on the Board of Directors of Canadian Tire Bank and as a director and Chair of the Investment Committee of the Insurance Corporation of British Columbia. He is also Chair of the Audit Committee of C.A. Bancorp and Prime Restaurants Royalty Income Fund. He is in addition a member of the Board of UBC Investment Management Inc. and a Chairman of Alberta Enterprise Corp.
Patrick J. Cairns Alberta, Canada	Senior Vice President	Senior Vice President of AOG since June 2001. Prior thereto, Mr. Cairns was Vice President, Evaluations with the Enerplus Group of Companies, which companies specialize in the management of oil and gas income funds and royalty trusts.
Craig Blackwood Alberta, Canada	Vice President, Finance	Vice President, Finance of AOG since January 27, 2009. 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	Vice President, Exploitation	Vice-President, Exploitation since June 23, 2006. Prior thereto, Vice President Exploitation and Operations of Ketch Resources Ltd. since January 2005; 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.
Weldon M. Kary Alberta, Canada	Vice President, Geosciences and Land	Vice President, Geosciences and Land since February 14, 2005. Prior thereto, Manager, Geology and Geophysics with AOG since May 23, 2001. Prior thereto, Exploration Manager at Palliser Energy Corp. when Palliser was purchased by Search Energy Corp, the predecessor entity of AOG.
Jay P. Reid Alberta, Canada	Corporate Secretary	Partner, Burnet, Duckworth & Palmer LLP, a Calgary-based law firm.

Notes:

(1) Member of the Audit Committee.
(2) Member of the Human Resources, Compensation and Corporate Governance Committee.
(3) Member of the 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. Howard was the President, Chief Executive Officer and Director of Sunoma Energy Corp. Immediately upon his resignation from the executive and board of directors, Sunoma Energy Corp. filed for Court protection.
(8) Mr. McIntosh is currently 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) staying all claims and actions against Fortress and its assets and allowing Fortress to prepare a plan of arrangement for its creditors if necessary. The Order is in effect until March 31, 2011, at which time the matter will be reviewed by the Court. In addition, on February 25, 2011, Fortress was notified by the TSX that it will be delisted effective March 31, 2011 for failure to meet minimum listing criteria, as a result of the sale of substantially all of its oil and gas assets.

As at March 22, 2011 the directors and executive officers of AOG, as a group, beneficially owned, directly or indirectly, or exercised control or direction over, 2,193,077 Common Shares, or approximately 1.3% of the issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Other than as disclosed above, no current director or officer 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, 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 resulted, after the director, executive officer or securityholder holding a sufficient number of securities of AOG to affect materially the control of AOG 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.

No current director or officer or security holder 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, 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.

In addition, no current director or officer 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.

No current director or officer 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. See also "*Interest of Management and Others in Material Transactions*".

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 and foreign exchange rates. 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, 2010, there were 164,092,009 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.

Debentures

The Debentures pay interest semi-annually and are convertible at the option of the holder into Common Shares at the applicable conversion price per Common Shares plus accrued and unpaid interest. The details of the Debentures including the balance outstanding as at the date hereof are as follows:

	7.75%	**8.00%**	**5.00%**
Trading symbol	AAV.DB.D	AAV.DB.G	AAV.DB.H
Issue date	Sep. 15, 2004	Nov. 13, 2006	Dec. 31, 2009
Maturity date	Dec. 1, 2011	Dec. 31, 2011	Jan. 30, 2015
Conversion price	$21.00	$20.33	$8.60
Outstanding	$46,766,000	$15,528,000	$86,250,000

The convertible debentures are redeemable prior to their maturity dates, at the option of the Corporation, upon providing appropriate days advance notification as per the terms of the applicable debenture indenture. The redemption prices for the various debentures, plus accrued and unpaid interest, is dependent on the redemption periods and are as follows:

Convertible Debenture	Redemption Periods	Price
7.75%	After December 1, 2009 and before December 1, 2011	$1,000
8.00%	After December 31, 2010 and before December 31, 2011	$1,025
5.00%	After January 31, 2013 and on or before January 30, 2015 (provided that the Current Market Price exceeds 125% of Conversion Price)	$1,000

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" following the completion of the Trust Conversion on July 9, 2009. The following table sets forth the trading history of the Common Shares for the year ended December 31, 2010.

Period	High	Low	Volume
	($)	($)	
TSX Trading			
2010			
January	7.68	6.69	8,885,203
February	7.49	6.54	9,839,050
March	8.32	6.70	15,349,819
April	7.52	6.85	8,839,632
May	7.33	5.69	10,930,384
June	7.30	6.15	13,824,278
July	6.81	6.00	9,916,422
August	6.65	6.01	11,490,349
September	6.75	6.16	9,707,938
October	6.68	6.14	11,625,283
November	7.03	6.31	10,286,384
December	6.92	6.32	10,845,059
NYSE Trading (U.S.$)			
2010			
January	7.45	6.27	4,173,200
February	7.17	6.07	3,247,063
March	8.07	6.56	8,806,931
April	7.49	6.75	3,753,088
May	7.24	5.31	4,240,822
June	7.18	5.79	4,318,350
July	6.60	5.55	3,099,924
August	6.50	5.66	2,491,724
September	6.50	5.97	2,590,810
October	6.64	5.96	2,631,209
November	6.90	6.19	2,931,697
December	6.85	6.23	2,347,971

7.75% Debentures

The 7.75% Debentures are listed for trading on the TSX under the symbol "AAV.DB.D". The following table sets forth the high and low trading prices and the aggregate trading volume of the 7.75% Debentures as reported by the TSX for the periods indicated.

Period	High ($)	Low ($)	Volume
2010			
January	108.99	102.20	3,340
February	103.62	97.50	12,120
March	103.50	101.85	34,026
April	102.99	102.01	15,680
May	102.90	102.50	3,380
June	104.00	102.60	6,100
July	103.99	102.90	8,450
August	103.99	103.00	4,180
September	104.00	103.33	4,080
October	104.75	102.00	7,920
November	103.40	102.00	6,310
December	102.50	99.01	4,700

6.50% Debentures

The 6.50% Debentures matured on June 30, 2010 and were listed for trading on the TSX under the symbol "AAV.DB.E" until their maturity. The following table sets forth the high and low trading prices and the aggregate trading volume of the 6.50% Debentures as reported by the TSX for the period indicated.

Period	High ($)	Low ($)	Volume
2010			
January	101.06	100.77	10,380
February	101.50	100.90	25,980
March	101.50	100.20	21,300
April	101.40	100.65	19,300
May	100.71	100.30	25,560
June	100.30	100.00	11,010

8.00% Debentures

The 8.00% Debentures are listed for trading on the TSX under the symbol "AAV.DB.G". The following table sets forth the high and low trading prices and the aggregate trading volume of the 8.00% Debentures as reported by the TSX for the periods indicated.

Period	High ($)	Low ($)	Volume
2010			
January	105.00	102.31	1,130
February	104.10	103.50	1,950
March	105.50	103.41	2,070
April	103.61	103.51	1,250
May	104.00	103.62	2,710
June	103.75	103.63	470
July	104.40	103.86	230
August	105.00	104.01	890
September	105.00	103.91	1,860
October	104.01	103.61	2,820
November	103.51	102.90	1,050
December	103.00	102.70	480

5.00% Debentures

The 5.00% Debentures are listed for trading on the TSX under the symbol "AAV.DB.H". 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.

Period	High	Low	Volume
	($)	($)	
2010			
January	107.75	102.00	108,510
February	107.00	104.00	64,590
March	113.56	104.00	37,705
April	107.00	104.00	36,570
May	105.50	97.50	16,300
June	106.99	100.00	32,890
July	105.25	101.00	83,175
August	106.45	100.64	107,390
September	104.75	102.50	13,670
October	105.86	101.65	4,090
November	105.00	102.00	7,710
December	104.00	103.00	25,700

Cash Distributions

Prior to the completion of the Trust Conversion, Unitholders of the Trust of record on a distribution record date were entitled to receive distributions which were paid by the Trust to its Unitholders on the corresponding distribution payment date. The following is a summary of the distributions made by us for each of the three most recently completed financial years.

For the 2009 Period Ended	Distributions per Unit	Payment Date
January 31	$0.08	February 17, 2009
February 28	$0.04	March 16, 2009
Total:	$0.12	

For the 2008 Period Ended	Distributions per Unit	Payment Date
January 31	$0.12	February 15, 2008
February 29	$0.12	March 17, 2008
March 31	$0.12	April 15, 2008
April 30	$0.12	May 15, 2008
May 30	$0.12	June 16, 2008
June 30	$0.12	July 15, 2008
July 31	$0.12	August 15, 2008
August 31	$0.12	September 15, 2008
September 30	$0.12	October 15, 2008
October 31	$0.12	November 17, 2008
November 30	$0.12	December 15, 2008
December 31	$0.08	January 15, 2009
Total:	$1.40	

Note:

(1) On March 18, 2009 we announced that monthly distributions had been suspended with the final cash distribution paid to Unitholders on March 16, 2009 to Unitholders of record as of February 27, 2009. See "*General Development of the Business*".

ESCROWED SECURITIES

There are presently no AOG securities held in escrow.

LEGAL PROCEEDINGS

There are no outstanding legal proceedings which are for claims in excess of 10% of our current asset value to which we are a party or in respect of which any of our properties are subject, nor are there any such proceedings known to be contemplated.

REGULATORY ACTIONS

During the year ended December 31, 2010 there were (i) no penalties or sanctions imposed against the Trust or AOG or 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 the Trust or AOG that would likely be considered important to a reasonable investor in making an investment decision; and (iii) no settlement agreements the Trust or AOG 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 nominees for director of AOG, 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, 2010 or in any proposed transaction which has materially affected or would materially affect AOG.

Steven Sharpe, a director of AOG, will be a director of Longview following completion of the Longview Transaction. In addition, concurrent with closing of the Longview Offering, AOG will enter into the TSA pursuant to which AOG will provide the necessary personnel and technical services to manage Longview's business. The officers of Longview will be Kelly Drader (President and Chief Executive Officer), Craig Blackwood (Chief Financial Officer) and Andy Mah (Chief Operating Officer), each of which are executive officers of AOG. The officers of Longview will provide services to Longview under the TSA but will remain as employees of Advantage. See "*Recent Developments – Longview Transaction*".

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.

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 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 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 except for Mr. Jay Reid, the Corporate Secretary of AOG, who is a partner of Burnet, Duckworth & Palmer LLP, which law firm provides AOG with legal services.

AUDITORS, TRANSFER AGENT AND REGISTRAR

Our auditors are PricewaterhouseCoopers LLP, Chartered Accountants, 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 and the 5.00% Debentures, 7.75% Debentures and 8.00% Debentures.

AUDIT COMMITTEE INFORMATION

Composition of the Audit Committee

The audit committee (the "**Audit Committee**") is comprised of Messrs. Paul Haggis, Stephen Balog, Ronald McIntosh and Ms. Carol Pennycook. 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
Ronald A. McIntosh Alberta, Canada	Yes	Yes	Mr. McIntosh is the Chairman and member of audit committee of North American Energy Partners Inc., a publicly traded corporation. Mr. McIntosh was also the Chairman and a member of the audit committee of Tasman Exploration Ltd., a private oil and gas company. He is also a director of Fortress Energy Inc.
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 and currently serves on the Board of Directors of Canadian Tire Bank and as a director and Chair of the Investment Committee of the Insurance Corporation of British Columbia. He is also Chair of the Audit Committee of C.A. Bancorp and Prime Restaurants Royalty Income Fund, a member of the Board of UBC Investment Management Inc. and a 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	Mr. Balog is President of West Butte Management Inc., a private oil and gas consulting company. Prior thereto, Mr. Balog was President & Chief Operating Officer and a director of Tasman Exploration Ltd. from 2001 to June, 2007, and was a director of BelAir Energy Corporation, a junior public company. He accepted appointment to the Petroleum Advisory Committee, Alberta Securities Commission in 2009 and has a Bachelor of Science, Chemical Engineering.
Carol D. Pennycook Ontario, Canada	Yes	Yes	Ms. Pennycook is a partner at the Toronto offices of Davies Ward Phillips & Vineberg, LLP, a national law firm. Ms. Pennycook received her LLB in 1979 and has been a partner since 1986. A significant portion of Ms. Pennycook's practice involves financing transactions.

Pre-Approval of Policies and Procedures

We have adopted polices 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	2009	2010
Audit Fees	$663,000(1)	$645,000
Audit-Related Fees	55,000	251,350(2)
Tax Fees (these services included general tax consultations)	-	-

Note:

(1) Includes work related to Trust Unit and 5.00% Debenture offerings.
(2) Includes work related to prospectus for the Longview Transaction.

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, transportation, and marketing) as a result of legislation enacted by various levels of government and with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta and Saskatchewan, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these regulations or controls will affect the Corporation's operations in a manner materially different than they will affect other oil and natural gas companies of similar size. 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.

Pricing and Marketing

Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, the 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 and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

Natural Gas

The price of the vast majority of natural gas produced in western Canada is now determined through the liquid market established at the Alberta "NIT" hub rather than through direct negotiation between buyers and sellers. 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 must 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 and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

The governments of Alberta and Saskatchewan also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements, and market considerations.

Pipeline Capacity

As a result of pipeline expansions over the past several years, there is ample pipeline capacity to accommodate Current Production levels of oil and natural gas in western Canada and pipeline capacity does not generally limit the ability to produce and market such production.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada United States Free Trade Agreement. 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 prohibits discriminatory border restrictions and export taxes. NAFTA also 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.

Royalties and Incentives

General

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

On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" ("**NRF**") containing the Government's proposals for Alberta's new royalty regime which were subsequently implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*. The NRF took effect on January 1, 2009. On March 11, 2010, the Government of Alberta announced changes to Alberta's royalty system intended to increase Alberta's competitiveness in the upstream oil and natural gas sectors, which changes included a decrease in the maximum royalty rates for conventional oil and natural gas production effective for the January 2011 production month. Royalty curves incorporating the changes announced on March 11, 2010 were released on May 27, 2010. Alberta royalties in effect after December 31, 2010 are known as the "Alberta Royalty Framework" ("**ARF**").

With respect to conventional oil, the NRF eliminated the classification system used by the previous royalty structure which classified oil based on the date of discovery of the pool. Under the ARF, 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. Royalty rates for conventional oil under the NRF ranged from 0-50%, an increase from the previous maximum rates of 30-35% depending on the vintage of the oil, and rate caps were set at \$120 per barrel. Effective January 1, 2011, the maximum royalty payable under the ARF was reduced to 40%. The royalty curve for conventional oil announced on May 27, 2010 amends the price component of the conventional oil royalty formula to moderate the increase in the royalty rate at prices higher than \$535/m^3 compared to the previous royalty curve.

Royalty rates for natural gas under the ARF are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Royalty rates for natural gas under the NRF ranged from 5-50%, an increase from the previous maximum rates of 5-35%, and rate caps were set at \$16.59/GJ. Effective January 1, 2011, the maximum royalty payable under the ARF was reduced to 36%. The royalty curve for natural gas announced on May 27, 2010 amends the price component of the natural gas royalty formula to moderate the increase in the royalty rate at prices higher than $5.25/GJ compared to the previous royalty curve.

Oil sands projects are also subject to the ARF. Prior to payout, 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 and 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. An oil sands project reaches payout when its cumulative revenue exceeds its cumulative costs. Costs include specified allowed capital and operating costs related to the project plus a specified return allowance. As part of the implementation of the NRF, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the NRF or the ARF.

Producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold production taxes. The level of the freehold production tax is based on the volume of monthly production and a specified rate of tax for both oil and gas.

In April 2005, the Government of Alberta implemented the Innovative Energy Technologies Program (the "**IETP**"), which 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 is backed by a $200 million funding commitment over a five-year period beginning April 1, 2005 and provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

On April 10, 2008, the Government of Alberta introduced two new royalty programs to be implemented along with the NRF and intended to encourage the development of deeper, higher cost oil and gas reserves. A five-year program for conventional oil exploration wells over 2,000 metres provides qualifying wells with up to a $1 million or 12 months of royalty relief, whichever comes first, and a five-year program for natural gas wells deeper than 2,500 metres provides a sliding scale royalty credit based on depth of up to $3,750 per metre. On May 27, 2010, the natural gas deep drilling program was amended, retroactive to May 1, 2010, by reducing the minimum qualifying depth to 2,000 metres, removing a supplemental benefit of $875,000 for wells exceeding 4,000 metres that are spudded subsequent to that date, and including wells drilled into pools drilled prior to 1985, among other changes.

On November 19, 2008, in response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The 5-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well's life when production rates are expected to be the highest. Under this new program, companies drilling new natural gas or conventional deep oil wells (between 1,000 and 3,500 m) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. Pursuant to the changes made to Alberta's royalty structure announced on March 11, 2010, producers were only able to elect to adopt the transitional royalty rates prior to January 1, 2011 and producers that had already elected to adopt such rates as of that date were permitted to switch to Alberta's conventional royalty structure up until February 15, 2011. On January 1, 2014, all producers operating under the transitional royalty rates will automatically become subject to the ARF. The revised royalty curves for conventional oil and natural gas will not be applied to production from wells operating under the transitional royalty rates.

On March 3, 2009, the Government of Alberta announced a three-point incentive program in order to stimulate new and continued economic activity in Alberta. The program introduced a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program, both applying to conventional oil or natural gas wells drilled between April 1, 2009 and March 31, 2010. The drilling royalty credit provides up to a $200 per metre royalty credit for new wells and is primarily expected to benefit smaller producers since the maximum credit available will be determined using the company's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2010, favouring smaller producers with lower activity levels. The new well incentive program initially applied to wells that began producing conventional oil or natural gas between April 1, 2009 and March 31, 2010 and provided for a maximum 5% royalty rate for the first 12 months of production on a maximum of 50,000 barrels of oil or 500 MMcf of natural gas. In June, 2009, the Government of Alberta announced the extension of these two incentive programs for one year to March 31, 2011. On March 11, 2010, the Government of Alberta announced that the incentive program rate of 5% for the first 12 months of production would be made permanent, with the same volume limitations.

In addition to the foregoing, on May 27, 2010, in conjunction with the release of the new royalty curves, the Government of Alberta announced a number of new 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 on 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 on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010;

- 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.

The Emerging Resource and Technologies Initiative will be reviewed in 2014, and the Government of Alberta has committed to providing industry with three years notice at that time if it decides to discontinue the program.

Saskatchewan

In Saskatchewan, the amount payable as Crown royalty or freehold production tax in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is classified as "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil", "third tier oil", "new oil" and "old oil") depend on the finished drilling date of a well and are applied to each of the three crude oil types slightly differently. Heavy oil is classified as third tier oil (having a finished drilling date on or after January 1, 1994 and before October 1, 2004), fourth tier oil (having a finished drilling date on or after October 1, 2002) or new oil (not classified as either third tier oil or fourth tier oil). Southwest designated oil uses the same definitions of third and fourth tier oil but new oil is defined as conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002. For non-heavy oil other than southwest designated oil, the same classification is used but new oil is defined as conventional oil produced from a vertical well completed after 1973 and having a finished drilling date prior to 1994, whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil. Where average wellhead prices are below the established base prices of $100 per m^3 for third and fourth tier oil and $50 per m^3 for new oil and old oil, base royalty rates are applied. Base royalty rates are 5% for all fourth tier oil, 10% for heavy oil that is third tier oil or new oil, 12.5% for southwest designated oil that is third tier oil or new oil, 15% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 20% for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30% for all fourth tier oil, 25% for heavy oil that is third tier oil or new oil, 35% for southwest designated oil that is third tier oil or new oil, 35% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 45% for old oil.

The amount payable as Crown royalty or freehold production tax in respect of natural gas production is determined by a sliding scale based on a reference price (which is the greater of the amount obtained by the producer and a prescribed minimum price), the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. Like conventional oil, natural gas is classified as "non-associated gas" or "associated gas" and royalty rates are determined according to the finished drilling date of the respective well. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on natural gas produced in association with oil is less than on non-associated natural gas. Non-associated gas is classified as new gas (having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of more than 3,500 m^3 of gas for every m^3 of oil, and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties.

On December 9, 2010, the Government of Saskatchewan enacted the *Freehold Oil and Gas Production Tax Act, 2010* which replaces the existing *Freehold Oil and Gas Production Tax Act* and is intended to facilitate more efficient payment of freehold production taxes by industry. No regulations have been passed with respect to the calculation of freehold production taxes under the new Act.

As with conventional oil production, base prices are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of $50 per thousand m^3 for third and fourth tier gas and $35 per thousand m^3 for new gas and old gas, base royalty rates are applied. Base royalty rates are 5% for all fourth tier gas, 15% for third tier or new gas, and 20% for old gas. Where average well-head prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30% for all fourth tier gas, 35% for third tier and new gas, and 45% for old gas.

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, including the following:

- *Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 8,000 m^3 for deep development vertical oil wells, 4,000 m^3 for non-deep exploratory vertical oil wells and 16,000 m^3 for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations);

- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 m^3 for qualifying exploratory gas wells;

- *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 6,000 m^3 for non-deep horizontal oil wells and 16,000 m^3 for deep horizontal oil wells (more than 1,700 metres or within certain formations);

- *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002* treating incremental production from waterflood projects as fourth tier oil for the purposes of royalty calculation;

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005* providing Crown royalty and freehold tax determinations based in part on the profitability of enhanced recovery projects pre- and post-payout;

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing on or after April 1, 2005* providing a Crown royalty of 1% of gross revenues on enhanced oil recovery projects pre-payout and 20% post-payout and a freehold production tax of 0% on operating income from enhanced oil recovery projects pre-payout and 8% post-payout;

- *Royalty/Tax Regime for High Water-Cut Oil Wells* granting "third tier oil" royalty/tax rates to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities; and

- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013* providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 m^3 for horizontal gas wells.

In 1975, the Government of Saskatchewan introduced a Royalty Tax Rebate ("**RTR**") as a response to the Government of Canada disallowing crown royalties and similar taxes as a deductible business expense for income tax purposes. As of January 1, 2007, the remaining balance of any unused RTR will be limited in its carry forward to seven years since the Government of Canada's initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial taxable income. Saskatchewan's RTR will be wound down as a result of the Government if Canada's plan to reintroduce full deductibility of provincial resource royalties for corporate income tax purposes.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. 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. Oil and natural gas located in such provinces can also be privately owned 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.

Each of the provinces of Alberta and Saskatchewan 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.

In Alberta, the NRF includes 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. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. The order in which these agreements will receive the reversion notice will depend on their vintage and location, with the older leases and licenses receiving reversion notices first beginning in January 2011. Leases and licences that were granted prior to January 1, 2009 but continued after that date will not be subject to shallow rights reversion until they reach the end of their primary term and are continued (at which time deep rights reversion will be applied); thereafter, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the 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 requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. 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 for pollution damage, and the imposition of material fines and penalties.

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 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. The *Alberta Land Stewardship Act* (the "**ALSA**") was proclaimed in force in Alberta on October 1, 2009, providing the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA are deemed to be legislative instruments equivalent to regulations and are 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, approvals and authorizations in order 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. Although no regional plans have been established under the ALSA, the planning process is underway for the Lower Athabasca Region (which contains the majority of oil sands development) and the South Saskatchewan Region. While the potential impact of the regional plans established under the ALSA cannot yet be determined, it is clear that such regional plans may have a significant impact on land use in Alberta and may affect the oil and gas industry.

Climate Change Regulation

Federal

In December 2002, the Government of Canada ratified the Kyoto Protocol ("**Kyoto Protocol**"), which requires a reduction in greenhouse gas ("**GHG**") emissions by signatory countries between 2008 and 2012. The Kyoto Protocol officially came into force on February 16, 2005 and commits Canada to reduce its greenhouse gas emissions levels to 6% below 1990 "business-as-usual" levels by 2012.

On February 14, 2007, the House of Commons passed Bill C-288, *An Act to ensure Canada meets its global climate change obligations under the Kyoto Protocol*. The resulting *Kyoto Protocol Implementation Act* came into force on June 22, 2007. Its stated purpose is to "ensure that Canada takes effective and timely action to meet its obligations under the Kyoto Protocol and help address the problem of global climate change." It requires the federal Minister of the Environment to, among other things, produce an annual climate change plan detailing the measures to be taken to ensure Canada meets its obligations under the Kyoto Protocol. It also authorizes the establishment of regulations respecting matters such as emissions limits, monitoring, trading and enforcement.

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 greenhouse gases 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 which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets apply to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets.

The Updated Action Plan makes a distinction between "Existing Facilities" and "New Facilities". For Existing Facilities, the Updated Action Plan requires an emissions intensity reduction of 18% below 2006 levels by 2010 followed by a continuous annual emissions intensity improvement of 2%. "New Facilities" are defined as facilities beginning operations in 2004 and include both greenfield facilities and major facility expansions that (i) result in a 25% or greater increase in a facility's physical capacity, or (ii) involve significant changes to the processes of the facility. New Facilities will be given a 3-year grace period during which no emissions intensity reductions will be required. Targets requiring an annual 2% emissions intensity reduction will begin to apply in the fourth year of commercial operation of a New Facility. Further, emissions intensity targets for New Facilities will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time. The method of applying this cleaner fuel standard has not yet been determined. In addition, the Updated Action Plan indicates that targets for the adoption of carbon capture and storage ("**CCS**") technologies will be developed for oil sands in-situ facilities, upgraders and coal-fired power generators that begin operations in 2012 or later. These targets will become operational in 2018, although the exact nature of the targets has not yet been determined.

Given the large number of small facilities within the upstream oil and gas and natural gas pipeline sectors, facilities within these sectors will only be subject to emissions intensity targets if they meet certain minimum emissions thresholds. That threshold will be (i) 50,000 tonnes of CO_2 equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 equivalents per facility per year for the upstream oil and gas facility; and (iii) 10,000 boe/d/company. These regulatory thresholds are significantly lower than the regulatory threshold in force in Alberta, discussed below. In all other sectors governed by the Updated Action Plan, all facilities will be subject to regulation.

Four separate compliance mechanisms are provided for in the Updated Action Plan in respect of the above targets: Regulated entities will be able to use Technology Fund contributions to meet their emissions intensity targets. The contribution rate for Technology Fund contributions will increase over time, beginning at $15 tonnes per CO_2 equivalent for the 2010-12 period, rising to $20 in 2013, and thereafter increasing at the nominal rate of GDP growth. Maximum contribution limits will also decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce greenhouse gas emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as described above.

The offset system is intended to encourage emissions reductions from activities outside of the regulated sphere, allowing non-regulated entities to participate in and benefit from emissions reduction activities. In order to generate offset credits, project proponents must propose and receive approval for emissions reduction activities that will be verified before offset credits will be issued to the project proponent. Those credits can then be sold to regulated entities for use in compliance or non-regulated purchasers that wish to either purchase the offset credits for cancellation or banking for future use or sale.

Under the Updated Action Plan, regulated entities will also be able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol which facilitates investment by developed nations in emissions-reduction projects in developing countries. The purchase of such Emissions Reduction Credits will be restricted to 10% of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations.

Finally, a one-time credit of up to 15 million tonnes worth of emissions credits will be awarded to regulated entities for emissions reduction activities undertaken between 1992 and 2006. These credits will be both tradable and bankable.

The United Nations Framework Convention on Climate Change is working towards establishing a successor to the Kyoto Protocol. From December 7 to 18, 2009, a meeting between government leaders and representatives from approximately 170 countries in Copenhagen, Denmark (the "**Copenhagen Conference**") resulted in the Copenhagen Accord, which reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. From November 29 to December 10, 2010, a meeting between representatives from approximately 190 countries in Cancun, Mexico resulted in the Cancun Agreements, in which developed countries committed to additional measures to help developing countries deal with climate change. Unlike the Kyoto Protocol, however, neither the Copenhagen Accord nor the Cancun Agreements establish binding GHG emissions reduction targets.

In response to the Copenhagen Accord, the Government of Canada indicated on January 29, 2010 that it will seek to achieve a 17% reduction in greenhouse gas emissions from 2005 levels by 2020. This goal is similar to the goal expressed in previous policy documents which were discussed above.

Although draft regulations for the implementation of the Updated Action Plan were intended to be published in the fall of 2008 and become binding on January 1, 2010, no such regulations have been proposed to date. Further, representatives 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 greenhouse gas emissions regulation. As a result, it is unclear to what extent, if any, the proposals contained in the Updated Action Plan will be implemented.

On December 23, 2010, the United States Environmental Protection Agency indicated its intention to impose greenhouse gas emissions standards for fossil fuel-fired power plants by July, 2011 and for refineries by December, 2011.

Alberta

Alberta enacted the *Climate Change and Emissions Management Act* (the "**CCEMA**") on December 4, 2003, amending it 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 similar to the Updated Action Plan and aims for a 50% reduction from 1990 emissions relative to GDP by 2020.

Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year are subject to comply with the CCEMA. Similarly to the Updated Action Plan, the CCEMA and the associated *Specified Gas Emitters Regulation* make a distinction 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 to 88% of their baseline for 2008 and subsequent years, with their baseline being established by the average of the ratio of the total annual emissions to production for the years 2003 to 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 Specified Gas Emitters Regulation. New Facilities are required to reduce their emissions intensity by 2% from baseline in the fourth year of commercial operation, 4% of baseline in the fifth year, 6% of baseline in the sixth year, 8% of baseline in the seventh year, and 10% of baseline in the eighth year. Unlike the Updated Action Plan, the CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA contains similar compliance mechanisms as the Updated Action Plan. Regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund (the "**Fund**") at a rate of $15 per tonne of CO2 equivalent. Unlike the Updated Action Plan, CCEMA contains no provisions for an increase to this contribution rate. Emissions credits can 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. Unlike the Updated Action Plan, the CCEMA does not contemplate a linkage to external compliance mechanisms such as the Kyoto Protocol's Clean Development Mechanism.

On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act*, 2010, which 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.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate greenhouse gas emissions in the province. The MRGGA received Royal

Assent on May 20, 2010 and will come into force on proclamation. Regulations under the MRGGA have also yet to be proclaimed, but draft versions indicate that Saskatchewan will adopt the goal of a 20% reduction in greenhouse gas emissions from 2006 levels by 2020 and permit the use of pre-certified investment credits, early action credits and emissions offsets in compliance, similar to both the federal and Alberta climate change initiatives. It remains unclear whether the scheme implemented by the MRGGA will be based on emissions intensity or an absolute cap on emissions.

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.

Possible Failure to Realize Anticipated Benefits of the Longview Transaction

The Corporation is proposing to complete the Longview Transaction to strengthen its position in the oil and natural gas industry and to create the opportunity to realize certain benefits. Achieving the benefits of the Longview Transaction depends in part on successfully consolidating functions and integrating operations, procedures and personnel in a timely and efficient manner, as well as the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the businesses and operations of Longview with those of the Corporation pursuant to the TSA. The integration of Longview's operations with those of the Corporation will require the dedication of management effort, time and resources, which may divert management's focus and resources from other strategic opportunities and from operational matters during this process.

In addition, achieving the benefits of the Longview Transaction depends in part on factors outside of the Corporation's control, including, but not limited to, commodity prices, regulatory regimes and tax and royalty regimes. The purchase price for the Acquired Assets will be partially based on engineering and economic assessments made by independent petroleum engineers as well as actual historical financial and operating results. These assessments and historical results include a number of material assumptions and factors regarding matters such as recoverability and marketability of oil, natural gas and NGLs, future prices of oil, natural gas and NGLs, and 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 operators of the Acquired Assets, the Corporation and Longview. All such assessments involve a measure of geological and engineering uncertainty which could result in lower production and reserves than that attributed to the Acquired Assets.

Possible Failure to Complete the Longview Transaction

The Longview Transaction is subject to normal commercial risk that the Longview Transaction may not be completed on the terms negotiated or at all.

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by numerous factors beyond its control. 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. The Corporation may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

The prices of oil and natural gas prices may be volatile and subject to fluctuation. Any 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 as a result of lower prices, which could result in reduced production of oil or 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 of these factors could result in a material decrease in the Corporation's expected net production revenue and a reduction in its oil and gas acquisition, development and exploration activities. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions, in the United States and Canada, the actions of OPEC, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and 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.

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

In addition, bank borrowings available to the Corporation may, in part, be determined by the Corporation's borrowing base. A sustained material decline in prices from historical average prices could reduce the Corporation's borrowing base, therefore reducing the bank credit available to the Corporation which could require that a portion, or all, of the Corporation's bank debt be repaid.

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, any existing reserves the Corporation may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Corporation's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Corporation will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, management of the Corporation may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Corporation.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, 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, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely 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 hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, 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. In accordance with industry practice, the Corporation is not fully insured against all of these risks, nor are all such risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Corporation could incur significant costs. 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.

Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and continued in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating 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. Although economic conditions improved towards the latter portion of 2009, these factors have negatively impacted company valuations and may impact the performance of the global economy going forward.

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. If the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. In addition, uncertain levels of near term industry activity coupled with the present global credit crisis exposes the Corporation to additional access to capital risk. 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. From time to time, the Corporation may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's 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. If the Corporation's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to the Corporation. Continued uncertainty in domestic and international credit markets could materially affect the Corporation's ability to access sufficient capital for its capital expenditures and acquisitions, and as a result, may have a material adverse effect on the Corporation's ability to execute its business strategy and on its business, financial condition, results of operations and prospects.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGLs reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth herein 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 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 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 thereof and such variations could be material.

Estimates 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 and 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 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 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 has not been updated and thus does not reflect changes in the Corporation's reserves since that date.

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 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;
- changes in regulations;
- 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 not be able to effectively market the oil and natural gas that it produces.

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, if commodity prices increase beyond the levels set in such agreements, the Corporation will not benefit from such increases and the Corporation may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, the Corporation will not benefit from the fluctuating exchange rate.

Issuance of Debt

From time to time the Corporation may enter into transactions to acquire assets or the 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 equity and/or 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.

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.

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.

Variations in Foreign Exchange Rates and Interest Rates

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Material increases in the value of the Canadian dollar negatively impact the Corporation's production revenues. Future Canadian/United States exchange rates could accordingly impact 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, which could negatively impact the market price of the Common Shares of the Corporation.

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. See "*Industry Conditions*". Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for natural gas and crude oil and increase the Corporation's costs, any 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 gas operations, the Corporation will require licenses from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

Geo-Political Risks

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle-East, and other areas of the world, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore 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 subject to 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 will not have insurance to protect against the risk from terrorism.

Climate Change

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". Recently, representatives from approximately 170 countries met in Copenhagen, Denmark to attempt to negotiate a successor to the Kyoto Protocol. Pursuant to the resulting Copenhagen Accord, a non-binding political consensus rather than a binding international treaty such as the Kyoto Protocol, the Government of Canada revised its emissions reduction targets slightly. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases and require the Corporation to comply with Alberta's greenhouse gas emissions legislation contained in the *Climate Change and Emissions Management Amendment Act* and the *Specified Gas Emitters Regulation*. The Corporation may also be required comply with the regulatory scheme for greenhouse gas emissions ultimately adopted by the federal government, which is now expected to be modified to ensure consistency with the regulatory scheme for greenhouse gas emissions adopted by the United States. The direct or indirect costs of these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The future implementation or modification of greenhouse gases regulations, whether to meet the limits required by the Kyoto Protocol, the Copenhagen Accord or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Corporation. 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. See "*Industry Conditions – Climate Change Regulation*".

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 spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such 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 regulations, 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.

Competition

The petroleum industry is competitive in all its phases. The Corporation competes with numerous other organizations 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 and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources.

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, such 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.

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.

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 impact 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.

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 to defeat the Corporation's claim which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Seasonality

The level of activity in the Canadian oil and 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. Also, certain oil and 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 declines in the demand for the goods and services of 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 makes acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as 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 business may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of, so that the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Corporation, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Corporation.

Operational Dependence

Other companies operate some of the assets in which the Corporation has an interest. As a result, 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 therefore depends upon a number of factors that may be outside of the Corporation's control, including 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.

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 of the Corporation are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA. See "*Conflicts of Interest*".

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of 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.

Dividends

The Corporation has not paid any dividends on its outstanding shares. Payment of dividends in the future will be dependent on, among other things, the cash flow, results of operations and financial condition of the Corporation, the need for funds to finance ongoing operations and other considerations as the board of directors of the Corporation considers relevant.

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 material non-compliance with the applicable NYSE Rules; (iii) submit an executed annual written affirmation to the NYSE, as well as an 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 listed under the NYSE. AOG has reviewed the NYSE listing standards 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 financial statements and management's discussion and analysis for the year ended December 31, 2010.

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, 2010, 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 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 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
Chief Executive Officer

(signed) *"Kelly I. Drader"*
Kelly I. Drader
President and Chief Financial Officer

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

(signed) *"John Howard"*
John Howard
Director

March 22, 2011

SCHEDULE "B"

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

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, 2010. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, 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 attributed to proved plus probable reserves, estimated using forecast prices and costs on a before tax basis and calculated using a discount rate of 10%, included in the reserves data of the Company evaluated by us as of December 31, 2010, 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, 2010, prepared October 2010 to February 2011		nil	2,515,972	nil	2,515,972
Total			**nil**	**2,515,972**	**nil**	**2,515,972**

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 16, 2011

Original Signed by Cameron P. Six, P. Eng.
Cameron P. Six, P. Eng.
Manager, Engineering and Associate

Original Signed by Alec Kovaltchouk, P. Geol
Alec Kovaltchouk, P. Geol.
Manager, Geoscience and Associate

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

Original Signed by Thomas K.Schenk, P. Eng
Thomas K. Schenk, P. Eng.
Petroleum Engineer

Original Signed by Ian E.Ooi, P. Eng
Ian E. Ooi, P. Eng.
Petroleum Engineer

Original Signed by Tanja M. Hale, P. Eng
Tanja M. Hale, P. Eng.
Senior Petroleum Engineer

Original Signed by Harry J. Helwerda, P. Eng., FEC
Harry J. Helwerda, P. Eng., FEC
Executive Vice-President and Director