UNITEDSTATES
SECURITIESANDEXCHANGECOMMISSION
Washington, D.C. 20549

OMB APPROVAL
OMB Number: 3235-0381 Expires: April 30, 2015 Estimated average burden hours per response. 429.93

FORM 40-F

[Check one]

☐ REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934

OR

☑ ANNUAL REPORT PURSUANT TO SECTION 13(a) OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended: **December 31, 2014** Commission File Number: **001-34406**

ADVANTAGE OIL & GAS LTD.
(Exact name of Registrant as specified in its charter)

N/A
(Translation of Registrant's name into English (if applicable))

ALBERTA
(Province or other jurisdiction of incorporation or organization)

1311
(Primary Standard Industrial Classification Code Number (if applicable))

N/A
(I.R.S. Employer Identification Number (if applicable))

Suite 300, 440 – 2 Avenue SW, Calgary, Alberta T2P 5E9 (403) 718-8000
(Address and telephone number of Registrant's principal executive offices)

Corporation Service Company
1133 Avenue of Americas, 31st Floor, New York, NY 10036 1-800-927-9800
(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)

Securities registered or to be registered pursuant to Section 12(b) of the Act.

Title of each class	Name of each exchange on which registered
Common Shares	**New York Stock Exchange**

Securities registered or to be registered pursuant to Section 12(g) of the Act.

None
(Title of Class)

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act.
None
(Title of Class)

For annual reports, indicate by check mark the information filed with this Form:

Annual information form ☑ Audited annual financial statements ☑

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report.

Common Shares: 170,067,650

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files).

Yes ☐ No ☐

DOCUMENTS INCLUDED IN THIS FORM

The following documents are included in the Form:

No.	Document
1.	Annual Information Form of the Registrant for the year ended December 31, 2014 (filed herein as Exhibit 99.1)
2.	Consolidated Financial Statements of the Registrant for the fiscal year ended December 31, 2014, prepared under International Financial Reporting Standards as issued by the International Accounting Standards Board (filed herein as Exhibit 99.2)
3.	Consolidated Management's Discussion and Analysis of the Registrant for the fiscal year ended December 31, 2014 (filed herein as Exhibit 99.3).
4.	Consent of PricewaterhouseCoopers LLP to the inclusion of the Auditors' Report dated March 25, 2015 on the Registrant's Audited Consolidated Financial Statements for the fiscal year ended December 31, 2014.
5.	Consent of Sproule Associates Limited to the incorporation by reference herein of its Statement of Reserves Data and other Information in Form 51-101F1, which statement and report is contained in the Registrant's Annual Information Form for the fiscal year ended December 31, 2014.
6.	CEO Certification pursuant to rule 13a-14(a) of the Exchange Act.
7.	CFO Certification pursuant to rule 13a-14(a) of the Exchange Act.
8.	CEO Certification pursuant to U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
9.	CFO Certification pursuant to U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

PRINCIPAL DOCUMENTS

A. Annual Information Form

For the Registrant's Annual Information Form for the fiscal year ended December 31, 2014, see Exhibit 99.1 of this Annual Report on Form 40-F.

B. Audited Annual Financial Statements

For the Registrant's Audited Consolidated Financial Statements for the year ended December 31, 2014, including the report of its Independent Auditor with respect thereto, see Exhibit 99.2 of this Annual Report on Form 40-F.

C. Consolidated Management's Discussion and Analysis

For the Registrant's Consolidated Management's Discussion and Analysis of the operating and financial results for the year ended December 31, 2014, see Exhibit 99.3 of this Annual Report on Form 40-F.

CERTIFICATIONS AND DISCLOSURES REGARDING CONTROLS AND PROCEDURES

A. CERTIFICATIONS. See Exhibits 31.1 and 31.2 to this Annual Report on Form 40-F.

B. DISCLOSURE CONTROLS AND PROCEDURES. As of the end of the Registrant's fiscal year ended December 31, 2014, an evaluation of the effectiveness of the Registrant's "disclosure controls and procedures" (as such term is defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the "Exchange Act")) was carried out by the Registrant's management with the participation of the principal executive officer and principal financial officer. Based upon that evaluation, the Registrant's principal executive officer and principal financial officer have concluded that as of the end of that fiscal year, the Registrant's disclosure controls and procedures are effective to ensure that information required to be disclosed by the Registrant in reports that it files or submits under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms and (ii) accumulated and communicated to the Registrant's management, including its principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

It should be noted that while the Registrant's principal executive officer and principal financial officer believe that the Registrant's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the Registrant's disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Reference is made in the "Evaluation of Disclosure Controls and Procedures" and "Evaluation of Internal Controls over Financial Reporting" sections of Management's Discussion and Analysis of the Registrant for the fiscal year ended December 31, 2014, included herein.

C. MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING. The required disclosure is included in "Management's Report on Internal Control over Financial Reporting" that accompanies the Registrant's Consolidated Financial Statements for the fiscal year ended December 31, 2014, filed as part of this Annual Report on Form 40-F.

D. ATTESTATION REPORT OF THE INDEPENDENT AUDITOR. The required disclosure is included in the "Independent Auditor's Report" that accompanies the Registrant's Consolidated Financial Statements for the fiscal year ended December 31, 2014, filed as part of this Annual Report on Form 40-F.

E. CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING. During the fiscal year ended December 31, 2014, there were no significant changes in the Registrant's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Registrant's internal control over financial reporting. Reference is made in the "Evaluation of Internal Controls over Financial Reporting" section of Management's Discussion and Analysis of the Registrant for the fiscal year ended December 31, 2014, included herein.

NOTICES PURSUANT TO REGULATION BTR

None.

CODE OF ETHICS FOR CHIEF EXECUTIVE OFFICER AND SENIOR FINANCIAL OFFICERS

The Registrant has adopted a Code of Ethics for its senior officers, principal financial officer and controller or principal accounting officer, directors and employees. This code applies to the President and Chief Executive Officer, Vice President Finance and Chief Financial Officer, Senior Vice President, Directors and employees. It is available on the Registrant's web site at www.advantageog.com and in print to any shareholder who requests it. All amendments to the code, and all waivers of the code with respect to any of the officers covered by it, will be posted on the Registrant's web site and provided in print to any shareholder who requests them.

AUDIT COMMITTEE

Identification of Audit Committee

The following individuals comprise the entire membership of the Advantage Audit Committee: Paul Haggis, Grant Fagerheim and Stephen Balog.

Audit Committee Financial Experts

Paul G. Haggis has been determined by the board of the Registrant to meet the "audit committee financial expert" criteria prescribed by the Securities and Exchange Commission and has been designated as audit committee financial expert for the Audit Committee of the board of the Registrant.

Each of the directors serving on the Audit Committee has also been determined by the board of the Registrant to be independent within the criteria established by the New York Stock Exchange, Inc. for audit committee membership.

PRINCIPAL ACCOUNTING FEES AND SERVICES – INDEPENDENT AUDITORS

Fees payable to the Registrant's independent auditors for the years ended December 31, 2014 and December 31, 2013, totaled $500,000 and $488,600, respectively, as detailed in the following tables. All funds are in Canadian dollars.

The following table discloses fees billed to the Registrant by its current auditors, PricewaterhouseCoopers LLP:

	Year ended December 31, 2014	Year ended December 31, 2013
Audit Fees	$ 355,000	$ 382,000
Audit Related Fees	68,000	$ 66,000
Tax Fees	35,000	$ 40,600
All Other Fees	42,000	$ 0
TOTAL	$ 500,000	$ 488,600

The nature of the services provided by the Registrant's independent auditors under each of the categories indicated in the table is described below.

Audit Fees

Audit fees were for professional services rendered by the Registrant's independent auditors for the audit of the Registrant's annual financial statements and services provided in connection with statutory and regulatory filings or engagements. These services include audit or review of financials forming part of such prospectus.

Audit-Related Fees

Audit-related fees were for assurance and related services reasonably related to the performance of the audit or review of the annual statements and are not reported under "Audit Fees" above.

Tax Fees

Tax fees were for tax advice and tax planning professional services. These services consisted of general tax planning and advisory services relating to common forms of domestic and international taxation (i.e., income tax, capital tax, goods and services tax, scientific research and experimental development tax credits).

All Other Fees

Work related to Secondary Offering.

PREAPPROVAL POLICIES AND PROCEDURES

In 2014, Advantage's Audit Committee pre-approved all audit, audit-related and tax fees. The Audit Committee will be informed routinely as to the non-audit services actually provided by the auditor pursuant to this pre-approval process. The auditors also present the estimate for the annual audit related services to the Audit Committee for approval prior to undertaking the annual audit of the financial statements.

OFF-BALANCE SHEET ARRANGEMENTS

None.

CONTRACTUAL OBLIGATIONS

	Payments due by period (Cdn$MM)				
	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Building Leases	$ 5.2	$ 1.1	$ 2.3	$ 1.8	$ -
Pipeline/Transportation	$ 119.5	$ 17.1	$ 37.7	$ 31.3	$ 33.4
Bank Indebtedness(1) (3)	$ 120.4	$ 6.8	$ 113.6	$ -	$ -
Convertible Debenture(2) (3)	$ 88.4	$ 88.4	$ -	$ -	$ -
Total Contractual Obligations	$ 333.5	$ 113.4	$ 153.6	$ 33.1	$ 33.4

(1) As at December 31, 2014, the Corporation's bank indebtedness was governed by a credit facility agreement with a syndicate of financial institutions. Under the terms of the agreement, the facility is reviewed annually, with the next review scheduled in June 2015. The facility is revolving and 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. Management fully expects that the facility will be extended at each annual review.

(2) As at December 31, 2014, Advantage had an $86.2 million convertible debenture outstanding that was convertible to common shares based on an established conversion price. The convertible debenture matured on January 30, 2015, and was settled from the Credit Facilities.

(3) Amounts include estimated amounts of interest.

DISCLOSURES PURSUANT TO REQUIREMENTS OF THE NEW YORK STOCK EXCHANGE

Presiding Director at Meetings of Non-Management Directors

The Registrant schedules regular executive sessions in which the Registrant's "non-management directors" (as that term is defined in the rules of the New York Stock Exchange) meet without management participation. Ron McIntosh serves as the presiding director (the "Chair of the Board") at such sessions. Each of the Registrant's non-management directors is "independent" as such term is used in the rules of the Canadian Securities Commissions and the New York Stock Exchange Corporate Governance Standards.

Communication with Non-Management Directors

Shareholders may send communications to the Registrant's non-management directors by writing to Investors Relations, EY Tower, Suite 300, 440 - 2 Avenue SW, Calgary, Alberta T2P 5E9, or calling the toll free number at 1-866-393-0393. Communications will be referred to the Chair of the Board for appropriate action. The status of all outstanding concerns addressed to the Chair of the Board will be reported to the board of directors as appropriate.

Corporate Governance Guidelines

According to NYSE Rule 303A.09, a listed company must adopt and disclose a set of corporate governance guidelines with respect to specified topics and must disclose any significant ways in which its practices differ from those followed by US domestic companies under the NYSE rules. Such guidelines and disclosures are required to be posted on the listed company's website. The Registrant has adopted the required guidelines and made the required disclosures, all of which are available on the Registrant's website at www.advantageog.com and in print to any shareholder who requests them.

Board Committee Charters

Advantage's Audit Committee Charter, the Terms of Reference of the Human Resources, Compensation and Corporate Governance Committee and the Terms of Reference for the Independent Reserve Evaluation Committee are available for viewing on the Registrant's website at www.advantageog.com and are available in print to any person who requests them. Requests for copies of these documents should be made by contacting: Investor Relations, EY Tower, Suite 300, 440 - 2 Avenue SW, Calgary, Alberta T2P 5E9.

UNDERTAKING

The Registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

CONSENT TO SERVICE OF PROCESS

The Registrant has previously filed with the Commission a Form F-X in connection with the Common Shares.

Any change to the name or address of the agent for service of process of the Registrant shall be communicated promptly to the Securities and Exchange Commission by an amendment to the Form F-X referencing the file number of the relevant registration statement.

EXHIBITS

The following exhibits are filed as part of this report.

Exhibit Number	Description
23.1	Consent of PricewaterhouseCoopers LLP to the inclusion of the Auditors' Report dated March 25, 2015 on the Registrant's Audited Consolidated Financial Statements for the fiscal year ended December 31, 2014.
23.2	Consent of Sproule Associates Limited to the incorporation by reference herein of its Statement of Reserves Data and other Information in Form 51-101F1, which statement and report is contained in the Registrant's Annual Information Form for the fiscal year ended December 31, 2014.
31.1	CEO Certification pursuant to rule 13a-14(a) of the Exchange Act.
31.2	CFO Certification pursuant to rule 13a-14(a) of the Exchange Act.
32.1	CEO Certification pursuant to U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	CFO Certification pursuant to U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	Annual Information Form of the Registrant for the year ended December 31, 2014.
99.2	Consolidated Financial Statements of the Registrant for the fiscal year ended December 31, 2014, prepared under International Financial Reporting Standards as issued by the International Accounting Standards Board.
99.3	Consolidated Management's Discussion and Analysis of the Registrant for the fiscal year ended December 31, 2014.

SIGNATURE

Pursuant to the requirements of the Exchange Act, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this Annual Report on Form 40-F to be signed on its behalf by the undersigned, thereto duly authorized, in the City of Calgary, Province of Alberta, Canada.

Dated: March 25, 2015

ADVANTAGE OIL & GAS LTD.

By: /s/ Craig Blackwood
Name: Craig Blackwood
Title: Vice President Finance and Chief Financial Officer

Exhibit 23.1

March 26, 2015

Consent of Independent Auditor

We hereby consent to the inclusion in this Annual Report on Form 40-F for the year ended December 31, 2014 of Advantage Oil & Gas Ltd. of our report dated March 25, 2015, relating to the consolidated financial statements, and the effectiveness of internal control over financial reporting, which appears in this Annual Report.

We also consent to reference to PricewaterhouseCoopers LLP under the heading “Interests of Experts,” which appears in the Annual Information Form included in this Annual Report on Form 40-F, which is incorporated by reference in such Registration Statement.

PricewaterhouseCoopers LLP

Chartered Accountants

PricewaterhouseCoopers LLP, Chartered Accountants
111 5 Avenue SW, Suite 3100, Calgary, Alberta, Canada T2P 5L3
T: +1 403 509 7500, F: +1 403 781 1825, www.pwc.com/ca

Exhibit 23.2

March 25, 2015

Consent of Independent Engineers

We refer to our report entitled "Evaluation of the P&NG Reserves of Advantage Oil & Gas Ltd. (As of December 31, 2014)", dated February 5, 2015 (the "Report").

We hereby consent to the use of our name and references to excerpts from the Report in the Annual Report on Form 40-F of Advantage Oil & Gas Ltd. for the year ended December 31, 2014.

Sincerely,

SPROULE ASSOCIATES LIMITED

By: /s/ Attila A. Szabo
Name: Attila A. Szabo, P. Eng
Title: Vice-President Engineering, Canada and Director

EXHIBIT 31.1

CEO CERTIFICATION
PURSUANT TO RULE 13a-14(a) OF THE SECURITIES EXCHANGE ACT OF 1934

I, Andy J. Mah, certify that:

1. I have reviewed this annual report on Form 40-F of Advantage Oil & Gas Ltd.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: March 25, 2015

/s/ Andy J. Mah
Andy J. Mah
President and Chief Executive Officer

EXHIBIT 31.2

CFO CERTIFICATION
PURSUANT TO RULE 13a-14(a) OF THE SECURITIES EXCHANGE ACT OF 1934

I, Craig Blackwood, certify that:

1. I have reviewed this annual report on Form 40-F of Advantage Oil & Gas Ltd.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: March 25, 2015

/s/ Craig Blackwood
Craig Blackwood
Vice President Finance and Chief Financial Officer

EXHIBIT 32.1

CEO CERTIFICATION

PURSUANT TO U.S.C. SECTION 1350, AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Advantage Oil & Gas Ltd. (“Advantage”) on Form 40-F for the fiscal year ending December 31, 2014 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Andy J. Mah, President and Chief Executive Officer of Advantage, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Advantage.

Date: March 25, 2015

/s/ Andy J. Mah
Andy J. Mah
President and Chief Executive Officer

EXHIBIT 32.2

CFO CERTIFICATION

PURSUANT TO U.S.C. SECTION 1350, AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Advantage Oil & Gas Ltd. ("Advantage") on Form 40-F for the fiscal year ending December 31, 2014 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Craig Blackwood, Vice President Finance and Chief Financial Officer of Advantage, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Advantage.

Date: March 25, 2015

/s/ Craig Blackwood
Craig Blackwood
Vice President Finance and Chief Financial Officer

Exhibit 99.1

ADVANTAGE OIL & GAS LTD.

ANNUAL INFORMATION FORM

YEAR ENDED DECEMBER 31, 2014

March 25, 2015

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GLOSSARY OF TERMS

Selected Defined Terms

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Selected Defined Oil and Gas Terms

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

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

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

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

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

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

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

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

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

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

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

(d) provide improved recovery systems;

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

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

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

(c) dry hole contributions and bottom hole contributions;

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

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

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

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

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

"**gross**" means:

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

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

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

"**net**" means:

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

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

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

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

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

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

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

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

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

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

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

ABBREVIATIONS

Oil and Natural Gas Liquids

bbls	barrels
Mbbls	thousand barrels
MMbbls	million barrels
NGLs	natural gas liquids
stb	stock tank barrels of oil
Mstb	thousand stock tank barrels of oil
MMboe	million barrels of oil equivalent
boe/d	barrels of oil equivalent per day
bbls/d	barrels of oil per day

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
bcf	billion cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
MMcfe/d	million cubic feet equivalent per day
m^3	cubic metres
MMbtu	million British Thermal Units
GJ	Gigajoule

Other

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

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

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

CONVERSION

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

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

FORWARD-LOOKING STATEMENTS

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

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

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

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

The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this annual information form:

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

- changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry;
- geological, technical, drilling and processing problems and other difficulties in producing petroleum reserves; and
- the other factors discussed under "*Risk Factors*".

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

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

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

NON-GAAP MEASURES

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

Funds from operations, as presented, is based on cash provided by operating activities before expenditures on decommissioning liability and changes in non-cash working capital reduced for finance expense excluding accretion. Cash netbacks are dependent on the determination of funds from operations and include the primary cash sales and expenses on a per mcfe basis that comprise funds from operations.

ADVANTAGE OIL & GAS LTD.

General

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

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

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

Corporate Structure

As at December 31, 2014, the Corporation did not have any material direct or indirect subsidiaries, as the total assets and sales and operating revenues of the Corporation's subsidiaries, on a combined basis, does not exceed 10% of the consolidated assets and the consolidated sales and operating revenues of the Corporation.

GENERAL DEVELOPMENT OF THE BUSINESS

General

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

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

Three Year History

2012

Credit Facilities

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

2012 Secondary Offering

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

Non-Core Asset Dispositions

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

2013

Non-Core Asset Dispositions

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

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

Appointment of Financial Advisors and Strategic Alternatives Process

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

Credit Facilities

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

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

Changes in Directors and Management

On June 12, 2013, Ms. Sheila O'Brien resigned as a director of Advantage. On August 1, 2013, Mr. Kelly Drader resigned as Chief Financial Officer and a director of the Corporation to focus on his role as President and Chief Executive Officer of Longview. Mr. Craig Blackwood, the Vice-President Finance of the Corporation, assumed the role of Interim Chief Financial Officer and on February 4, 2014, Mr. Blackwood was appointed as Chief Financial Officer of the Corporation. On November 28, 2013, Mr. Lionel Derochie resigned as Vice President Operations of the Corporation and on December 31, 2013, Mr. Pat Cairns resigned as Senior Vice President of the Corporation in order to focus on their respective roles at Longview.

2014

Strategic Alternatives Process Conclusion

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

Three Year Development Plan and Glacier Phase VII Budget Approval

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

Termination of Technical Services Agreement

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

Credit Facilities

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

Change in Directors and Management

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

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

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

2014 Secondary Offering

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

Sale of Questfire Investments

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

Recent Developments

2015 Guidance and Development Plan Update

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

Anticipated Changes in the Business

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

Significant Acquisitions

The Corporation did not complete any acquisitions during the year ended December 31, 2014 for which disclosure is required under Part 8 of National Instrument of 51-102 *Continuous Disclosure Obligations*.

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

DESCRIPTION OF OUR BUSINESS AND OPERATIONS

General

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

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

Reorganizations

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

Bankruptcy and Similar Procedures

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

Specialized Skill and Knowledge

Advantage employs individuals with various professional skills in the course of pursuing its business plan. These professional skills include, but are not limited to, geology, geophysics, engineering, financial and business skills, which are widely available in the industry. Drawing on significant experience in the oil and gas business, Advantage believes its management team has a demonstrated track record of bringing together all of the key components to a successful exploration and production company: strong technical skills; expertise in planning and financial controls; ability to execute on business development opportunities; capital markets expertise; and an entrepreneurial spirit that allows Advantage to effectively identify, evaluate and execute on its business plan.

Human Resources

As at December 31, 2014, the Corporation employed 27 full-time employees, 23 of which are located in the head office and 4 of which are located in the field. The Corporation also retained 5 consultants in the head office.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

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

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

Disclosure of Reserves Data

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

The Sproule Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and the COGE Handbook. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which the Corporation believes is important to readers of this annual information form. Sproule was engaged to provide evaluations of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

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

There are numerous uncertainties inherent in estimating quantities of crude oil, natural gas and NGL reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this annual information form are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable crude oil, NGL and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its consolidated reserves will vary from estimates thereof and such variations could be material.

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

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

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

SUMMARY OF OIL AND GAS RESERVES
as at December 31, 2014
FORECAST PRICES AND COSTS

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

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

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

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
as at December 31, 2014
FORECAST PRICES AND COSTS

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

Notes:

(1) The unit values are based on net reserve volumes.
(2) Values are calculated by considering existing tax pools for Advantage in the evaluation of Advantage's oil and gas properties, and take into account current federal tax regulations. Values do not represent an estimate of the value at the business entity level, which may be significantly different. For information at the business entity level, please see Advantage's Consolidated Financial Statements and Management's Discussion and Analysis for the year ended December 31, 2014.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
as at December 31, 2014
FORECAST PRICES AND COSTS

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

Note:

(1) Values are calculated by considering existing tax pools for Advantage in the evaluation of Advantage's oil and gas properties, and take into account current federal tax regulations. Values do not represent an estimate of the value at the business entity level, which may be significantly different. For information at the business entity level, please see Advantage's Consolidated Financial Statements and Management's Discussion and Analysis for the year ended December 31, 2014.

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

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

Pricing Assumptions

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

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

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

Notes:

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

Weighted average historical prices, including hedging, realized by the Corporation for the year ended December 31, 2014, were $4.15/Mcf for natural gas, $93.26/bbl for crude oil, and $66.97/bbl for NGLs.

Reconciliations of Changes in Reserves

The following table sets forth a reconciliation of the Corporation's total gross proved, total gross probable and total gross proved plus probable reserves as at December 31, 2014 against such reserves as at December 31, 2013 based on forecast prices and cost assumptions. This table does not include any reserves attributable to Longview as at December 31, 2013.

RECONCILIATION OF
GROSS RESERVES
BY PRODUCT TYPE
FORECAST PRICES AND COSTS

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

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

The following table sets forth a reconciliation of the Corporation's total gross proved, total gross probable and total gross proved plus probable reserves as at December 31, 2014 against such reserves as at December 31, 2013 based on forecast prices and cost assumptions. This table represents the Corporation's and the Corporation's consolidated subsidiaries interest including 100% of Longview's reserves at December 31, 2013. As a result of the 2014 Secondary Offering, the Longview reserves were removed from the Corporation's consolidated reserves as represented in the following table as "dispositions" in 2014.

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

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

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

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by Sproule in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Proved and probable undeveloped reserves have been assigned in accordance with engineering and geological practices as defined under NI 51-101.

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

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

Proved Undeveloped Reserves

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

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

Probable Undeveloped Reserves

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

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

Significant Factors or Uncertainties

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on production forecasts, prices and economic conditions. The Corporation's reserves are evaluated by Sproule.

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

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

Future Development Costs

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

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

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

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

The interest or other costs of external funding are not included in the reserves and future net revenue estimates set forth above and would reduce the reserves and future net revenue to some degree depending upon the funding sources utilized. The Corporation does not anticipate that interest or other funding costs would make further development of any of the Corporation's assets uneconomic.

Other Oil and Gas Information

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

Property Descriptions

The following property descriptions are as of December 31, 2014 unless otherwise noted and reserves quoted are as reported in the Sproule Report.

Glacier, Alberta

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

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

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

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

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

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

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

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

Oil and Gas Wells

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

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

Properties with no Attributed Reserves

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

	Gross Acres	Net Acres
Alberta	108,939	88,527

We expect that rights to explore, develop and exploit 960 net acres of our undeveloped land holdings will expire by December 31, 2015. The land expirations do not consider our 2015 exploitation and development program that may result in extending or eliminating such potential expirations. We closely monitor land expirations as compared to our development program with the strategy of minimizing undeveloped land expirations relating to significant identified opportunities. Development of the Corporation's properties with no attributed reserves are subject to current industry conditions and uncertainties as indicated under "*Risk Factors*" herein.

Forward Contracts

Our operational results and financial condition will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely in recent years. Such prices are primarily determined by economic, and in the case of oil prices, political factors. Supply and demand factors, as well as weather, general economic conditions, and conditions in other oil and natural gas regions of the world also impact prices. Any upward or downward movement in oil and natural gas prices could have an effect on our financial condition and capital development.

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

Advantage has the following derivatives in place:

Natural gas - AECO

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

Additional Information Concerning Abandonment and Reclamation Costs

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

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

Tax Horizon

In 2014, we did not pay any income related taxes and it is expected, based on current legislation that no cash income taxes are to be paid by AOG prior to 2021. See "*Risk Factors*".

Capital Expenditures

The following tables summarize capital expenditures (including capitalized general and administrative expenses) related to our activities for the year ended December 31, 2014:

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

Exploration and Development Activities

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

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

Subject to, among other things, the availability of drilling rigs and weather that permits access to drill sites, in the first six months of 2015, we plan to drill 10 net wells and complete 6 net wells.

See "*Other Oil and Gas Information – Property Descriptions*" for a description of the Corporation's exploration and development activities.

Production Estimates

The following table sets out the volume of our production estimated for the year ended December 31, 2015 reflected in the estimate of future net revenue disclosed in the tables contained under "*Disclosure of Reserves Data*".

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

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

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

Production History

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

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

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

Notes:

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

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

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

Marketing

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

Cyclical and Seasonal Impact of Industry

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

Environmental Considerations

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

Health, Safety and Environmental

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

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

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

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

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

Competitive Conditions

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

DIRECTORS AND OFFICERS

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

Name, Province and Country of Residence	Position Held and Period Served as a Director or Officer(4)(5)	Principal Occupations During Past Five Years
Andy J. Mah Alberta, Canada	President since April 21, 2011, Chief Executive Officer since January 27, 2009 and a Director since June 23, 2006	President since April 21, 2011. Chief Executive Officer since January 27, 2009. President and Chief Operating Officer from June 23, 2006 to January 27, 2009. Chief Operating Officer of Longview from December 15, 2010 to November 7, 2013. Prior thereto, President of Ketch Resources Ltd. from October 2005 to June 2006. Chief Operating Officer of Ketch Resources Ltd. from January 2005 to September 2005. Prior thereto, Executive Officer and Vice President, Engineering and Operations of Northrock Resources Ltd. from August 1998 to January 2005.

Name, Province and Country of Residence	Position Held and Period Served as a Director or Officer[(4)(5)]	Principal Occupations During Past Five Years
Ronald A. McIntosh[(2)(3)(7)] Alberta, Canada	Director since September 25, 1998[(6)] Chairman since February 4, 2014	Chairman of North American Energy Partners Inc., a publicly traded corporation and a director of Fortaleza Energy Inc., previously known as Alvopetro Inc., formerly named Fortress Energy Inc. Mr. McIntosh has extensive experience in the energy business. His previous roles included President and Chief Executive Officer of Navigo Energy, Chief Operating Officer of Gulf Canada, Vice President Exploration and International of PetroCanada and Chief Operating Officer of Amerada Hess Canada.
Stephen E. Balog[(1)(2)(3)] Alberta, Canada	Director since August 16, 2007	Principal of Alconsult International Ltd. and President, West Butte Management Inc., private consulting companies that provide technical and business advisory services to oil and gas operators. Prior thereto, President and Chief Operating Officer and a Director of Tasman Exploration Ltd. from 2001 to June, 2007. Mr. Balog has extensive oil and gas industry experience in the management and operation of senior and junior production companies. He was a key contributor to the development and use of the Canadian Oil & Gas Evaluation Handbook as an industry standard for reserves evaluation, and has previously served on the Petroleum Advisory Committee, Alberta Securities Commission.
Grant Fagerheim[(1)(2)] Alberta, Canada	Director since May 26, 2014	Chairman, President and Chief Executive Officer of Whitecap Resources Inc., a public oil and gas company, since June, 2008. Prior thereto, Mr. Fagerheim was the President and Chief Executive Officer and a Director of Cadence Energy Inc. (formerly, Kereco Energy Ltd.), a public oil and gas company, from January 2005 to September 2008. Mr. Fagerheim received his Bachelor's degree in Education (Economics Minor) from the University of Calgary in 1983 and attended the Executive MBA at Queen's University in 1995. Mr. Fagerheim currently sits on the board of directors of PRD Energy Inc., a public oil and gas company.
Paul Haggis[(1)(2)(3)] Alberta, Canada	Director since November 7, 2008	Mr. Haggis' was President and Chief Executive Officer of Ontario Municipal Employees Retirement System (OMERS) from September 2003 to March 2007, Interim Chief Executive Officer of the Public Sector Pension Investment Board (PSPIB) during 2003 and Executive Vice-President, Development and Chief Credit Officer of Manulife Financial in 2002. Mr. Haggis has extensive financial markets and public board experience having served on the Board of Directors of Canadian Tire Bank until March 30, 2012. He was a director and Chair of the Investment Committee of the Insurance Corporation of British Columbia and currently serves as an advisor to the committee. He was also Chair of the Audit Committee of C.A. Bancorp and Prime Restaurants Royalty Income Fund. Currently he is on the Board of UBC Investment Management Inc., Canadian Pacific Railway, Athabasca Oil Corporation and is Chairman of Alberta Enterprise Corp. Mr. Haggis holds a Bachelor of Arts degree from the University of Western Ontario and is certified as a Chartered Director through the Directors College at McMaster University.
Craig Blackwood Alberta, Canada	Vice President, Finance since January 27, 2009 and Chief Financial Officer since August 1, 2013	Chief Financial Officer of AOG since August 1, 2013. Vice President, Finance of AOG since January 27, 2009. Chief Financial Officer of Longview from March 4, 2010 to February 4, 2014. Mr. Blackwood is a Chartered Accountant and was the Director of Finance of AOG from November 2004 to January 27, 2009.
Neil Bokenfohr Alberta, Canada	Senior Vice President, since March 27, 2014	Senior Vice President since March 27, 2014. Vice-President, Exploitation of AOG from June 23, 2006 to March 27, 2014. Vice-President, Exploitation of Longview from May 13, 2011 to November 7, 2013. Prior thereto, Vice President Exploitation and Operations of Ketch Resources Ltd. from January 2005 to June 2006; Vice President, Engineering of Bear Creek Energy Ltd. (and Crossfield Gas Corp. prior thereto) from March 2002 to January 2005. Prior thereto, Director of Exploitation for Calpine Canada Natural Gas Company from December 2000 to March 2002.
Jay P. Reid Alberta, Canada	Corporate Secretary, Since April, 2001	Partner at the Calgary based law firm of Burnet, Duckworth & Palmer LLP and has practiced corporate and securities law since 1990. He has served as a director or officer of a number of publicly listed issuers and currently serves as Corporate Secretary for Gear Energy Ltd., Madalena Energy Inc., Pinecrest Energy Inc. and a number of private issuers.

Notes:

(1) Member of the Audit Committee.
(2) Member of the Human Resources, Compensation and Corporate Governance Committee.
(3) Member of the Independent Reserve Evaluation Committee.
(4) AOG does not have an executive committee of the Board.
(5) AOG's directors shall hold office until the next annual general meeting of Shareholders or until each director's successor is appointed or elected pursuant to the ABCA.
(6) The period of time served by Ronald A. McIntosh as a director of AOG includes the period of time served as a director of Search prior to the Amalgamation, where applicable. Mr. McIntosh was appointed a director of post-Reorganization Search on May 24, 2001.
(7) Mr. McIntosh is a director of Fortress Energy Inc. ("**Fortress**"). On March 2, 2011, the Court of Queen's Bench of Alberta granted an order (the "**Order**") under the *Companies' Creditors Arrangement Act* (Canada) ("**CCAA**") staying all claims and actions against Fortress and its assets and allowing Fortress to prepare a plan of arrangement for its creditors if necessary. Fortress took such step in order to enable Fortress to challenge a reassessment issued by the Canada Revenue Agency ("**CRA**"). As a result of the reassessment, if Fortress had not taken any action, it would have been compelled to immediately remit one half of the reassessment to the CRA and Fortress did not have the necessary liquid funds to remit, although Fortress had assets in excess of its liabilities with sufficient liquid assets to pay all other liabilities and trade payables. Fortress believed that the CRA's position was not sustainable and vigorously disputed the CRA's claim. Fortress filed a Notice of Objection to the reassessment and on October 20, 2011 announced that its Notice of Objection was successful, CRA having confirmed there were no taxes payable. As the CRA claim had been vacated and no taxes or penalties were owing Fortress no longer required the protection of the Order under the CCAA and on October 28, 2011 the Order was removed. On March 3, 2011 the TSX suspended trading in the securities of Fortress due to Fortress having been granted a stay under the CCAA. In addition the securities regulatory authorities in Alberta, Ontario and Quebec issued a cease trade order with respect to Fortress for failure to file its annual financial statements for the year ended December 31, 2010 by March 31, 2011. The delay in filing was due to Fortress being granted the CCAA order on March 2, 2011 and the resulting additional time required by its auditors to deliver their audit opinion. The required financial statements and other continuous disclosure documents were filed on April 29, 2011 and the cease trade order was subsequently removed. On September 1, 2010 Fortress closed the sale of substantially all of its oil and gas assets. As a result of the sale Fortress was delisted from the TSX on March 30, 2011 as it no longer met minimum listing requirements. Fortress was renamed Alvopetro Inc. on November 24, 2012. Alvopetro Inc. was renamed Fortaleza Energy Inc. in November 2013.

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

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Other than as disclosed above:

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

(b) no director or executive officer of AOG or security holder holding a sufficient number of securities of AOG to affect materially the control of AOG is, as at the date of this annual information form, or has, within the last ten years prior to the date of this annual information form, been a director or executive officer of any company (including AOG) that, while such person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement for compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets;

(c) no director or executive officer of AOG or securityholder holding a sufficient number of securities of AOG to affect materially the control of AOG has, within the last ten years prior to the date of this document, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, officer or securityholder; and

(d) no director or executive officer of AOG or securityholder holding a sufficient number of securities of AOG to affect materially the control of AOG has been subject to: (i) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (ii) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

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

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

DIVIDEND POLICY

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

DESCRIPTION OF THE CORPORATION'S SECURITIES

Share Capital

The Corporation is authorized to issue an unlimited number of Common Shares, non-voting shares, preferred shares and exchangeable shares. As of December 31, 2014, there were 170,067,650 Common Shares issued and outstanding and there were no non-voting shares, preferred shares or exchangeable shares issued and outstanding.

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

Common Shares

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

Non-Voting Shares

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

Preferred Shares

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

5.00% Debentures

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

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

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

PRICE RANGE AND TRADING VOLUME OF SECURITIES

Common Shares

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

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

5.00% Debentures

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

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

Prior Sales

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

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTIONS ON TRANSFER

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

LEGAL PROCEEDINGS

There are no outstanding legal proceedings and Advantage and its subsidiaries were not involved in any legal proceedings during the year ended December 31, 2014, which involved claims in excess of 10% of the Corporation's current asset value and to which Advantage or its subsidiaries were a party or in respect of which any of its properties are subject, nor are there any such proceedings known to be contemplated.

REGULATORY ACTIONS

During the year ended December 31, 2014 there were: (i) no penalties or sanctions imposed against AOG or its subsidiaries by a court relating to securities legislation or by a securities regulatory authority; (ii) no other penalties or sanctions imposed by a court or regulatory body against AOG or its subsidiaries that would likely be considered important to a reasonable investor in making an investment decision; and (iii) no settlement agreements AOG or its subsidiaries entered into before a court relating to a securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as disclosed below, there were no material interests, direct or indirect, of directors and executive officers of AOG or its subsidiaries or nominees for director of AOG or its subsidiaries, any Shareholder who beneficially owns or directs or controls more than 10% of the Common Shares or any known associate or affiliate of such persons in any transaction during the year ended December 31, 2014 or in any proposed transaction which has materially affected or would materially affect AOG or its subsidiaries.

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

MATERIAL CONTRACTS

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

INTEREST OF EXPERTS

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

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

AUDITORS, TRANSFER AGENT AND REGISTRAR

Our auditors are PricewaterhouseCoopers LLP, Calgary, Alberta.

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

AUDIT COMMITTEE INFORMATION

Composition of the Audit Committee

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

Name, Province and Country of Residence	Independent	Financially Literate	Relevant Education and Experience
Grant Fagerheim Alberta, Canada	Yes	Yes	Chairman, President and Chief Executive Officer of Whitecap Resources Inc., a public oil and gas company, since June, 2008. Prior thereto, Mr. Fagerheim was the President and Chief Executive Officer and a Director of Cadence Energy Inc. (formerly, Kereco Energy Ltd.), a public oil and gas company, from January 2005 to September 2008. Mr. Fagerheim received his Bachelor's degree in Education (Economics Minor) from the University of Calgary in 1983 and attended the Executive MBA at Queen's University in 1995. Mr. Fagerheim currently sits on the board of directors of PRD Energy Inc., a public oil and gas company.
Paul Haggis Alberta, Canada	Yes	Yes	Mr. Haggis' was President and Chief Executive Officer of Ontario Municipal Employees Retirement System (OMERS) from September 2003 to March 2007, Interim Chief Executive Officer of the Public Sector Pension Investment Board (PSPIB) during 2003 and Executive Vice-President, Development and Chief Credit Officer of Manulife Financial in 2002. Mr. Haggis has extensive financial markets and public board experience having served on the Board of Directors of Canadian Tire Bank until March 30, 2012. He was a director and Chair of the Investment Committee of the Insurance Corporation of British Columbia and currently serves as an advisor to the committee. He was also Chair of the Audit Committee of C.A. Bancorp and Prime Restaurants Royalty Income Fund. Currently he is on the Board of UBC Investment Management Inc., Canadian Pacific Railway, Athabasca Oil Corporation and is Chairman of Alberta Enterprise Corp. Mr. Haggis holds a Bachelor of Arts degree from the University of Western Ontario and is certified as a Chartered Director through the Directors College at McMaster University.
Stephen Balog Alberta, Canada	Yes	Yes	Principal of Alconsult International Ltd. and President, West Butte Management Inc., private consulting companies that provide technical and business advisory services to oil and gas operators. Prior thereto, President and Chief Operating Officer and a Director of Tasman Exploration Ltd. from 2001 to June, 2007. Mr. Balog has extensive oil and gas industry experience in the management and operation of senior and junior production companies. He was a key contributor to the development and use of the Canadian Oil & Gas Evaluation Handbook as an industry standard for reserves evaluation, and has previously served on the Petroleum Advisory Committee, Alberta Securities Commission.

Pre-Approval of Policies and Procedures

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

AUDIT COMMITTEE CHARTER

The following is a summary of our Audit Committee Charter which was originally approved by the AOG Board of Directors on April 30, 2002 and amended in April 2003, April 2004, June 2005, August 2005, October, 2005 and September, 2009:

Purpose

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

The Audit Committee's primary objectives are:

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

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

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

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

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

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

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

Composition

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

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

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

Meetings

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

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

Responsibilities and Duties

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

Documents/Reports Review

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

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

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

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

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

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

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

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

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

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

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

Independent Auditors

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

13. Approve the compensation of the external auditors.

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

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

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

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

18. Oversee the establishment of an internal audit function.

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

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

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

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

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

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

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

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

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

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

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

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

Financial Reporting Processes

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

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

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

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

Process Improvement

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

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

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

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

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

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

34. Establish a procedure for:

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

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

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

Ethical and Legal Compliance

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

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

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

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

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

Other

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

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

AUDIT SERVICE FEES

Auditor Services Fees

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

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

Notes:

(1) "Audit Fees" include fees necessary to perform the annual audit of the Corporation's consolidated financial statements.
(2) "Audit-Related Fees" include services that are traditionally performed by the auditor. These audit-related services include quarterly reviews of the Corporation's consolidated financial statements.
(3) "Tax Fees" include fees for all tax services other than those included in "Audit Fees" and "Audit-Related Fees". This category includes fees for tax compliance, tax planning and general tax advice, including the preparation and filing of Scientific Research & Experimental Development Tax Credits.
(4) "Other Fees" represents fees related to the 2014 Secondary Offering.

INDUSTRY CONDITIONS

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

Pricing and Marketing

Oil

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

Natural Gas

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

The North American Free Trade Agreement

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

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

Royalties and Incentives

General

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

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

Alberta

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

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

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

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

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

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

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

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

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

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

Land Tenure

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

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

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

Production and Operation Regulations

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

Environmental Regulation

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

Federal

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

Alberta

The regulatory landscape in Alberta has undergone a transformation from multiple regulatory bodies to a single regulator for upstream oil and gas, oil sands and coal development activity. On June 17, 2013, the Alberta Energy Regulator (the "**AER**") assumed the functions and responsibilities of the former Energy Resources Conservation Board, including those found under the *Oil and Gas Conservation Act* ("**ABOGCA**"). On November 30, 2013, the AER assumed the energy related functions and responsibilities of Alberta Environment and Sustainable Resource Development ("**AESRD**") in respect of the disposition and management of public lands under the *Public Lands Act*. On March 29, 2014, the AER assumed the energy related functions and responsibilities of AESRD in the areas of environment and water under the *Environmental Protection and Enhancement Act* and the *Water Act*, respectively. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind the transformation to a single regulator is the creation of an enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

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

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

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

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

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

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

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

Liability Management Rating Programs

Alberta

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

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

- a 25% increase to the prescribed average reclamation cost for each individual well or facility (which will increase a licensee's deemed liabilities);
- a $7,000 increase to facility abandonment cost parameters for each well equivalent (which will increase a licensee's deemed liabilities);
- a decrease in the industry average netback from a five-year to a three-year average (which will affect the calculation of a licensee's deemed assets, as the reduction from five to three years means the average will be more sensitive to price changes); and
- a change to the present value and salvage factor, increasing to 1.0 for all active facilities from the current 0.75 for active wells and 0.50 for active facilities (which will increase a licensee's deemed liabilities).

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

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

Climate Change Regulation

Federal

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

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

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

Alberta

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

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

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

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

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

RISK FACTORS

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

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

Prices, Markets and Marketing

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

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

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

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

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

Global Financial Markets

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

Exploration, Development and Production Risks

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

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

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

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

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

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

Project Risks

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

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

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

Reserve Estimates

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

- historical production from the properties;

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

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

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

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

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

Gathering and Processing Facilities, Pipeline Systems and Rail

The Corporation delivers its products through gathering and processing facilities and pipeline systems some of which it does not own. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines, and in particular the processing facilities, could result in the Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation's production. Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. Furthermore, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically and it is projected to continue in this upward trend. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Corporation's business and, in turn, the Corporation's financial condition, results of operations and cash flows.

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

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

Substantial Capital Requirements

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

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

Further, if the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

Additional Funding Requirements

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

Because of global economic volatility, the Corporation may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, the Corporation's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of the Corporation's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production on the Corporation's properties.

Credit Facility Arrangements

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

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

Hedging

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

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

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

Management of Growth

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

Reliance on Key Personnel

The Corporation's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have any key person insurance in effect for the Corporation. The contributions of the existing management team to the immediate and near term operations of the Corporation are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

Competition

The petroleum industry is competitive in all of its phases. The Corporation competes with numerous other entities in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Corporation's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. The Corporation's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price, methods, and reliability of delivery and storage.

Hydraulic Fracturing

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

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

Availability of Drilling Equipment and Access

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

Seasonality

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

Variations in Foreign Exchange Rates and Interest Rates

World oil and natural gas prices are quoted in United States dollars. The Canadian/United States dollar exchange rate, which fluctuates over time, consequently affects the price received by Canadian producers of oil and natural gas. Material increases in the value of the Canadian dollar relative to the United States dollar will negatively affect the Corporation's production revenues. Accordingly, Canadian/United States exchange rates could affect the future value of the Corporation's reserves as determined by independent evaluators.

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

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

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites.

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental legislation, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. See "*Industry Conditions*". The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Corporation's costs, either of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, the Corporation will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake. In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, the Corporation's business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada).

Insurance

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

Third Party Credit Risk

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may affect a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

Liability Management

Alberta has developed a liability management program designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder becomes defunct. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes of the ratio of the Corporation' deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted. See "*Industry Conditions*".

Tax Horizon

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

Operational Dependence

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

Title to Assets

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

Expiration of Licences and Leases

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

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation considers acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired businesses may require substantial management effort, time and resources diverting management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets may be periodically disposed of so the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Corporation, if disposed of, may realize less than their carrying value on the financial statements of the Corporation.

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

Climate Change

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases which may require the Corporation to comply with greenhouse gas ("**GHG**") emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and a participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction in GHG emissions from 2005 levels by 2020. These GHG emission reduction targets are not binding, however. Some of the Corporation's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. The direct or indirect costs of compliance with these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition.

Geo-Political Risks

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

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

Aboriginal Claims

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

Issuance of Debt

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

Market Price of Common Shares

The trading price of securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to the Corporation's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices or current perceptions of the oil and gas market. Similarly, the market price of the Common Shares could be subject to significant fluctuations in response to variations in the Corporation's operating results, financial condition, liquidity and other internal factors. The price at which the Common Shares will trade cannot be accurately predicted.

Dilution

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

Conflicts of Interest

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

Dividends

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

Internal Controls

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

Cost of New Technologies

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

Alternatives to and Changing Demand for Petroleum Products

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

Royalty Regimes

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

Litigation

In the normal course of the Corporation's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, related to personal injuries, property damage, property tax, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Corporation and as a result, could have a material adverse effect on the Corporation's assets, liabilities, business, financial condition and results of operations.

Breach of Confidentiality

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

Income Taxes

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

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

Expansion into New Activities

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

Forward-Looking Information May Prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on the Corporation's forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risk and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate. Additional information on the risks, assumption and uncertainties are found under "*Forward-Looking Statements*".

DISCLOSURE PURSUANT TO THE REQUIREMENTS OF THE NEW YORK STOCK EXCHANGE

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

ADDITIONAL INFORMATION

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

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Common Shares and securities authorized for issuance under equity compensation plans, will be contained in the Corporation's Information Circular for the most recent annual meeting of shareholders that involved the election of directors of AOG. Additional financial information is provided for in the Corporation's Consolidated financial statements and management's discussion and analysis for the year ended December 31, 2014.

SCHEDULE "A"

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

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

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

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

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

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

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

The independent reserves evaluation committee of the board of directors of AOG has reviewed AOG's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the independent reserves evaluation committee, approved:

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

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

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

(signed) *"Andy Mah"*
Andy Mah
President and Chief Executive Officer

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

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

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

March 25, 2015

SCHEDULE "B"

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

To the Board of Directors of Advantage Oil & Gas Ltd. (the "**Company**"):

1. We have evaluated the Company's Reserves Data as at December 31, 2014. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014, estimated using forecast prices and costs.

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

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

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

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2014, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

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

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

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

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

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta
February 5, 2015

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

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

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

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

Exhibit 99.2

Consolidated Financial Statements

Management's Responsibility for Financial Statements

The Management of Advantage Oil & Gas Ltd. (the "Corporation") is responsible for the preparation and presentation of the consolidated financial statements together with all operational and other financial information contained in the annual report. The consolidated financial statements have been prepared by Management in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board and utilize the best estimates and careful judgments of Management, where appropriate. Operational and other financial information contained throughout the annual report is consistent with that provided in the consolidated financial statements.

Management has developed and maintains a system of internal controls designed to provide reasonable assurance that all transactions are accurately and reliably recorded, that the consolidated financial statements accurately report the Corporation's operating and financial results within acceptable limits of materiality, that all other operational and financial information presented is accurate, and that the Corporation's assets are properly safeguarded.

The Audit Committee, comprised of non-management directors, acts on behalf of the Board of Directors to ensure that Management fulfills its financial reporting and internal control responsibilities. The Audit Committee is responsible for meeting regularly with Management, the external auditors, and the internal auditors to discuss internal controls over financial reporting processes, auditing matters and various aspects of financial reporting. The Audit Committee reviewed the consolidated financial statements with Management and the external auditors, and recommended approval to the Board of Directors. The Board of Directors has approved these consolidated financial statements.

PricewaterhouseCoopers LLP, an independent firm of Chartered Accountants, appointed by the shareholders as the external auditor of the Corporation, has audited the consolidated statement of financial position as at December 31, 2014 and 2013, and the consolidated statements of comprehensive income (loss), changes in shareholders' equity and cash flows for the years ended December 31, 2014 and 2013. The external auditors conducted their audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States) and have unlimited and unrestricted access to the Audit Committee.

Andy J. Mah
President and Chief Executive Officer
March 25, 2015

Craig Blackwood
Vice President Finance and Chief Financial Officer

Management's Report on Internal Control over Financial Reporting

The Management of Advantage Oil & Gas Ltd. (the "Corporation") is responsible for establishing and maintaining adequate internal control over financial reporting for the Corporation as such term is defined in Rule 13a-15(f) of the Securities Exchange Act of 1934, as amended. Under the supervision of our Chief Executive Officer and Chief Financial Officer, we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on our assessment, we have concluded that as of December 31, 2014, our internal control over financial reporting was effective.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to the financial statement preparation and presentation. Further, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP, the Corporation's independent firm of Chartered Accountants, was appointed by the shareholders to audit and provide an independent opinion on both the consolidated financial statements and the Corporation's internal control over financial reporting as at December 31, 2014, as stated in their Auditor's Report. PricewaterhouseCoopers LLP has provided such opinion.

Andy J. Mah
President and Chief Executive Officer
March 25, 2015

Craig Blackwood
Vice President Finance and Chief Financial Officer

March 25, 2015

Independent Auditor's Report

To the Shareholders of Advantage Oil & Gas Ltd.

We have completed integrated audits of Advantage Oil & Gas Ltd.'s 2014 and 2013 consolidated financial statements and its internal control over financial reporting as at December 31, 2014. Our opinions, based on our audits are presented below.

Report on the consolidated financial statements
We have audited the accompanying consolidated financial statements of Advantage Oil & Gas Ltd., which comprise the consolidated statement of financial position as at December 31, 2014 and December 31, 2013 and the consolidated statements of comprehensive income (loss), changes in shareholders' equity, and cash flows for the years then ended, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements
Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility
Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement. Canadian generally accepted auditing standards also require that we comply with ethical requirements.

An audit involves performing procedures to obtain audit evidence, on a test basis, about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the company's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting principles and policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion on the consolidated financial statements.

Opinion
In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Advantage Oil & Gas Ltd. as at December 31, 2014 and December 31, 2013 and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Report on internal control over financial reporting
We have also audited Advantage Oil & Gas Ltd.'s internal control over financial reporting as at December 31, 2014, based on criteria established in Internal Control - Integrated Framework (2013), issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

Management's responsibility for internal control over financial reporting
Management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting.

Auditor's responsibility
Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control, based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances.

We believe that our audit provides a reasonable basis for our audit opinion on the company's internal control over financial reporting.

Definition of internal control over financial reporting
A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that: (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

pwc

Inherent limitations
Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Opinion
In our opinion, Advantage Oil & Gas Ltd. maintained, in all material respects, effective internal control over financial reporting as at December 31, 2014, based on criteria established in Internal Control - Integrated Framework (2013) issued by COSO.

PricewaterhouseCoopers LLP

Chartered Accountants

Consolidated Statement of Financial Position
(thousands of Canadian dollars)

	Notes	December 31, 2014	December 31, 2013
ASSETS			
Current assets			
Trade and other receivables	5	$ 21,974	$ 32,016
Prepaid expenses and deposits		2,503	3,357
Derivative asset	10	31,595	143
Total current assets		**56,072**	**35,516**
Non-current assets			
Derivative asset	10	14,961	2,329
Investments	6	-	30,626
Exploration and evaluation assets	7	9,803	10,270
Property, plant and equipment	8	1,373,931	1,647,434
Deferred income tax asset	14	-	39,069
Total non-current assets		**1,398,695**	**1,729,728**
Total assets		**$ 1,454,767**	**$ 1,765,244**
LIABILITIES			
Current liabilities			
Trade and other accrued liabilities		$ 81,741	$ 93,893
Derivative liability	10	-	8,340
Convertible debenture	12	85,941	-
Total current liabilities		**167,682**	**102,233**
Non-current liabilities			
Derivative liability	10	-	1,183
Performance incentive plan	17(b)	512	-
Bank indebtedness	11	109,970	271,339
Convertible debenture	12	-	82,454
Decommissioning liability	13	48,878	100,616
Deferred income tax liability	14	33,399	3,006
Total non-current liabilities		**192,759**	**458,598**
Total liabilities		**360,441**	**560,831**
SHAREHOLDERS' EQUITY			
Share capital	15	2,234,959	2,229,598
Convertible debenture equity component	12	8,348	8,348
Contributed surplus		90,904	92,276
Deficit		(1,239,885)	(1,255,588)
Total shareholders' equity attributable to Advantage shareholders		**1,094,326**	**1,074,634**
Non-controlling interest		-	129,779
Total shareholders' equity		**1,094,326**	**1,204,413**
Total liabilities and shareholders' equity		**$ 1,454,767**	**$ 1,765,244**

Commitments (note 23)
See accompanying Notes to the Consolidated Financial Statements

On behalf of the Board of Directors of Advantage Oil & Gas Ltd.:

Paul G. Haggis, Director

Andy J. Mah, Director

Consolidated Statement of Comprehensive Income (Loss)

(thousands of Canadian dollars, except for per share amounts)	Notes	Year ended December 31 2014	2013
Continuing operations			
Natural gas and liquids sales	18	$ 215,653	$ 140,090
Less: royalties		(10,076)	(7,534)
Natural gas and liquids revenue		205,577	132,556
Operating expense		(15,412)	(20,515)
General and administrative expense	19	(9,579)	(24,426)
Depreciation expense	8	(85,460)	(72,140)
Exploration and evaluation expense	7	(53)	-
Finance expense	20	(14,792)	(18,225)
Gains (losses) on derivatives	10	35,236	(3,190)
Other income (expenses)	21	(10,527)	(3,979)
Income (loss) before taxes from continuing operations		**104,990**	**(9,919)**
Income tax recovery (expense)	14	(30,393)	1,622
Net income (loss) and comprehensive income (loss) from continuing operations		**74,597**	**(8,297)**
Discontinued operations			
Net income (loss) from discontinued operations	24	**(58,894)**	**4,915**
Net income (loss) and comprehensive income (loss)		**$ 15,703**	**$ (3,382)**
Net income (loss) per share	16		
Basic and diluted - from continuing operations		**$ 0.44**	**$ (0.05)**
Basic and diluted - from discontinued operations		**(0.35)**	**0.03**
Basic and diluted		**$ 0.09**	**$ (0.02)**

See accompanying Notes to the Consolidated Financial Statements

Consolidated Statement of Changes in Shareholders' Equity

(thousands of Canadian dollars)	Notes	Share capital	Convertible debenture equity component	Contributed surplus	Deficit	Total shareholders' equity attributable to Advantage shareholders	Non-controlling interest	Total shareholders' equity
Balance, December 31, 2013		$ 2,229,598	$ 8,348	$ 92,276	$ (1,255,588)	**$ 1,074,634**	$ 129,779	**$ 1,204,413**
Net income (loss) and comprehensive income (loss)					15,703	**15,703**	(85)	**15,618**
Share based compensation	15, 17	5,361	-	(1,372)	-	**3,989**	-	**3,989**
Change in ownership interest, share based compensation		-	-	-	-	**-**	334	**334**
Dividends declared by Longview ($0.04 per Longview share)		-	-	-	-	**-**	(1,032)	**(1,032)**
Disposition of Longview	3b, 24	-	-	-	-	**-**	(128,996)	**(128,996)**
Balance, December 31, 2014		**$ 2,234,959**	**$ 8,348**	**$ 90,904**	**$ (1,239,885)**	**$ 1,094,326**	**$ -**	**$ 1,094,326**
Balance, December 31, 2012		$ 2,229,598	$ 8,348	$ 84,962	$ (1,252,206)	**$ 1,070,702**	$ 138,008	**$ 1,208,710**
Net loss and comprehensive loss		-	-	-	(3,382)	**(3,382)**	5,981	**2,599**
Share based compensation	15, 17	-	-	7,314	-	**7,314**	-	**7,314**
Change in ownership interest, share based compensation		-	-	-	-	**-**	981	**981**
Dividends declared by Longview ($0.59 per Longview share)		-	-	-	-	**-**	(15,191)	**(15,191)**
Balance, December 31, 2013		**$ 2,229,598**	**$ 8,348**	**$ 92,276**	**$ (1,255,588)**	**$ 1,074,634**	**$ 129,779**	**$ 1,204,413**

See accompanying Notes to the Consolidated Financial Statements

Consolidated Statement of Cash Flows

(thousands of Canadian dollars)	Notes	Year ended December 31 2014	2013
Operating Activities			
Income (loss) before taxes from continuing operations		$ 104,990	$ (9,919)
Add (deduct) items not requiring cash:			
Share based compensation	15, 17	2,153	5,180
Depreciation expense	8	85,460	72,140
Exploration and evaluation expense	7	53	-
Unrealized loss (gain) on derivatives	10	(47,786)	6,043
Loss on sale of assets	21	1,489	6,354
Accretion income - Questfire Debenture	6, 21	(557)	(1,516)
Loss on disposition of Questfire Debenture	6	13,833	-
Unrealized loss (gain) - Questfire Class B Shares	6	(150)	900
Finance expense	20	14,792	18,225
Expenditures on decommissioning liability	13	(446)	(4,664)
Changes in non-cash working capital	22	(3,924)	6,623
Cash provided by operating activities - continuing operations		**169,907**	**99,366**
Cash provided by operating activities - discontinued operations	24	**12,434**	**65,651**
Cash provided by operating activities		**182,341**	**165,017**
Financing Activities			
Decrease in bank indebtedness	11	(44,038)	(7,260)
Interest paid		(9,956)	(11,756)
Cash used in financing activities - continuing operations		**(53,994)**	**(19,016)**
Cash provided by (used in) financing activities - discontinued operations	24	**435**	**(15,217)**
Cash used in financing activities		**(53,559)**	**(34,233)**
Investing Activities			
Expenditures on property, plant and equipment	8, 22	(221,810)	(139,716)
Expenditures on exploration and evaluation assets	7	(3,237)	(6,831)
Disposition of investments	6	17,500	-
Property dispositions		(211)	53,506
Cash used in investing activities - continuing operations		**(207,758)**	**(93,041)**
Cash provided by (used in) investing activities - discontinued operations	24	**78,976**	**(37,743)**
Cash used in investing activities		**(128,782)**	**(130,784)**
Net change in cash		-	-
Cash, beginning of year		-	-
Cash, end of year		$ -	$ -

See accompanying Notes to the Consolidated Financial Statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2014 and 2013

All tabular amounts are in thousands of Canadian dollars except as otherwise indicated.

1. Business and structure of Advantage Oil & Gas Ltd.

Advantage Oil & Gas Ltd. and its subsidiaries (together "Advantage" or the "Corporation") is an intermediate natural gas and liquids development and production corporation with a significant position in the Montney resource play located in Western Canada.

Advantage is domiciled and incorporated in Canada under the Business Corporations Act (Alberta). Advantage's head office address is 300, 440 – 2nd Avenue SW, Calgary, Alberta, Canada. The Corporation's primary listing is on the Toronto Stock Exchange and is also traded on the New York Stock Exchange as a Foreign Private Issuer, under the symbol "AAV".

2. Basis of preparation

(a) Statement of compliance

The Corporation prepares its consolidated financial statements in accordance with Canadian generally accepted accounting principles ("GAAP") as defined in the Handbook of the Canadian Institute of Chartered Accountants ("CICA Handbook"). The CICA Handbook incorporates International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. Publicly accountable enterprises, such as the Corporation, are required to apply these standards. Accordingly, these consolidated financial statements are prepared and issued under IFRS.

The accounting policies applied in these consolidated financial statements are based on IFRS issued and outstanding as of March 25, 2015, the date the Board of Directors approved the statements.

(b) Basis of measurement

The consolidated financial statements have been prepared on the historical cost basis, except as detailed in the Corporation's accounting policies in note 3.

The methods used to measure fair values of derivative instruments are discussed in note 10.

(c) Functional and presentation currency

These consolidated financial statements are presented in Canadian dollars, which is the Corporation's functional currency.

3. Significant accounting policies

The accounting policies set out below have been applied consistently to all years presented in these financial statements.

(a) Cash and cash equivalents

Cash consists of balances held with banks, and other short-term highly liquid investments with original maturities of three months or less from inception.

3. Significant accounting policies (continued)

(b) Basis of consolidation

(i) Subsidiaries

Subsidiaries are entities controlled by the Corporation. Control exists when the Corporation is exposed, or has rights to variable returns from its involvement with the entity and has the ability to affect those returns through its power over the entity. In assessing control, potential voting rights that currently are exercisable are taken into account. The financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases. The only significant operating subsidiary was Longview Oil Corp. ("Longview"), a public Canadian corporation that was a junior oil-focused development and production company with properties located in Western Canada. At December 31, 2013, Advantage owned 45.1% of the common shares of Longview. Because the remaining ownership was dispersed, Advantage was considered to control Longview. Therefore, Longview was accounted for on a consolidated basis in these financial statements. The remaining 54.9% ownership was disclosed as non-controlling interest. All inter-corporate balances, income and expenses resulting from inter-corporate transactions were eliminated.

On February 28, 2014, the Corporation closed an offering (the "Offering") to sell the 21.15 million Longview common shares for net proceeds of $90.2 million. The results of operations of Longview from January 1, 2014 to February 28, 2014 are consolidated into the results of operations of the Corporation. Because Longview was an operating segment, its results are presented as "discontinued operations" for the periods January 1, 2014 to February 28, 2014 and the year ended December 31, 2013 as required by IFRS 5, *non-current assets held for sale and discontinued operations* (see note 24). On February 28, 2014, Advantage derecognized all assets, liabilities and the non-controlling interest of Longview from the consolidated statement of financial position as it had lost control of Longview as defined in IFRS 10, *consolidated financial statements.*

(ii) Joint arrangements

A significant portion of the Corporation's natural gas and liquids activities involve joint operations. The consolidated financial statements include the Corporation's share of these joint operations and a proportionate share of the relevant revenue and related costs.

(c) Financial instruments

All financial instruments are initially recognized at fair value on the Consolidated Statement of Financial Position. Measurement of financial instruments subsequent to the initial recognition, as well as resulting gains and losses, is based on how each financial instrument was initially classified. The Corporation has classified each identified financial instrument into the following categories: fair value through profit or loss, loans and receivables, held to maturity investments, available for sale financial assets, and financial assets and liabilities at amortized cost. Fair value through profit or loss financial instruments are measured at fair value with gains and losses recognized in income immediately. Available for sale financial assets are measured at fair value with gains and losses, other than impairment losses, recognized in other comprehensive income and transferred to income when the asset is derecognized. Loans and receivables, held to maturity investments and financial liabilities at amortized cost, are recognized at amortized cost using the effective interest method and impairment losses are recorded in income when incurred.

Derivative instruments executed by the Corporation to manage market risk associated with volatile commodity prices are classified as fair value through profit or loss and recorded on the Consolidated Statement of Financial Position at fair value as derivative assets and liabilities. Gains and losses on these instruments are recorded as gains and losses on derivatives in the Consolidated Statement of Comprehensive Income (Loss) in the period they occur. Gains and losses on derivative instruments are comprised of cash receipts and payments associated with periodic settlement that occurs over the life of the instrument, and non-cash gains and losses associated with changes in the fair values of the instruments, which are remeasured at each reporting date and recorded on the Consolidated Statement of Financial Position.

On April 30, 2013, Advantage completed the sale of substantially all non-core assets. Proceeds received consisted of cash and non-cash consideration. The Questfire Class B Shares were classified as financial assets at fair value through profit or loss. The Questfire Debenture was classified as a financial asset at amortized cost. Questfire repurchased these assets by way of agreement on March 26, 2014, and their balance is $Nil at December 31, 2014. (see note 6).

3. Significant accounting policies (continued)

(d) Property, plant and equipment and exploration and evaluation assets

(i) Recognition and measurement

Exploration and evaluation costs

Pre-license costs are recognized in the Consolidated Statement of Comprehensive Income (Loss) as incurred.

All exploratory costs incurred subsequent to acquiring the right to explore for natural gas and liquids before technical feasibility and commercial viability of the area have been established are capitalized. Such costs can typically include costs to acquire land rights, geological and geophysical costs and exploration well costs.

Exploration and evaluation costs are not depreciated and are accumulated in cost centers by well, field or exploration area and carried forward pending determination of technical feasibility and commercial viability.

The technical feasibility and commercial viability of extracting a mineral resource from exploration and evaluation assets is considered to be generally determinable when proved or probable reserves are determined to exist. Upon determination of proved or probable reserves, exploration and evaluation assets attributable to those reserves are first tested for impairment and then reclassified from exploration and evaluation assets to development and production assets, net of any impairment loss.

Management reviews and assesses exploration and evaluation assets to determine if technical feasibility and commercial viability exist. If Management decides not to continue the exploration and evaluation activity, the unrecoverable costs are charged to exploration and evaluation expense in the period in which the determination occurs.

Development and production costs

Items of property, plant and equipment, which include natural gas and liquids properties, are measured at cost less accumulated depreciation and accumulated impairment losses. Costs include lease acquisition, drilling and completion, production facilities, decommissioning costs, geological and geophysical costs and directly attributable general and administrative costs related to development and production activities, net of any government incentive programs.

When significant parts of an item of property, plant and equipment, including natural gas and liquids properties, have different useful lives, they are accounted for as separate items (major components).

(ii) Subsequent costs

Costs incurred subsequent to development and production that are significant are recognized as natural gas and liquids property only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in comprehensive income as incurred. Such capitalized natural gas and liquids costs generally represent costs incurred in developing proved and probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or area basis. The carrying amount of any replaced or sold component is derecognized in accordance with our policies. The costs of the day-to-day servicing of property, plant and equipment are recognized in the Consolidated Statement of Comprehensive Income (Loss) as incurred.

(iii) Depreciation

The net carrying value of natural gas and liquids properties is depreciated using the units-of-production ("UOP") method by reference to the ratio of production in the period to the related proved and probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. Future development costs are estimated taking into account the level of development required to produce the reserves. These estimates are reviewed by independent reserve engineers at least annually.

3. Significant accounting policies (continued)

(d) Property, plant and equipment and exploration and evaluation assets (continued)

(iv) Dispositions

Gains and losses on disposal of an item of property, plant and equipment, including natural gas and liquids properties, are determined by comparing the proceeds from disposition with the carrying amount of property, plant and equipment and are recognized net within other income (expenses) in the Consolidated Statement of Comprehensive Income (Loss).

(v) Impairment

The carrying amounts of the Corporation's property, plant and equipment are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, the asset's recoverable amount is estimated. For the purpose of impairment testing of property, plant and equipment, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit" or "CGU").

Exploration and evaluation assets are assessed for impairment if sufficient data exists to determine technical feasibility and commercial viability, and facts and circumstances suggest that the carrying amount exceeds the recoverable amount. Exploration and evaluation assets are allocated to CGU's or groups of CGU's for the purposes of assessing such assets for impairment.

The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs of disposition. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved and probable reserves. Fair value less costs of disposition is assessed utilizing market valuation based on an arm's length transaction between active participants. In the absence of any such transactions, fair value less costs of disposition is estimated by discounting the expected after-tax cash flows of the cash generating unit at an after-tax discount rate that reflects the risk of the properties in the cash generating unit. The discounted cash flow calculation is then increased by a tax-shield calculation, which is an estimate of the amount that a prospective buyer of the cash generating unit would be entitled. The carrying value of the cash generating unit is reduced by the deferred tax liability associated with its property, plant and equipment.

Impairment losses on property, plant and equipment are recognized in the Consolidated Statement of Comprehensive Income (Loss) as impairment of natural gas and liquids properties and are separately disclosed. An impairment of exploration and evaluation assets is recognized as exploration and evaluation expense in the Consolidated Statement of Comprehensive Income (Loss).

(e) Decommissioning liability

A decommissioning liability is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Decommissioning liabilities are determined by discounting the expected future cash flows at a risk-free rate.

3. Significant accounting policies (continued)

(f) Share based compensation

Advantage accounts for share based compensation expense based on the fair value of rights granted under its share based compensation plans.

Advantage's Stock Option Plan ("Stock Option Plan") authorizes the Board of Directors to grant stock options to service providers, including directors, officers, employees and consultants of Advantage. Compensation cost related to the Stock Option Plan is recognized as share based compensation expense within general and administrative expense over the vesting period at fair value.

On April 14, 2014, the Board of Directors approved a Restricted and Performance Award Incentive Plan to provide share based compensation for service providers. Awards granted under this plan are presently expected to be settled in cash, as the Corporation has not sought the approval of shareholders required to settle the awards in shares. In accordance with the requirements of IFRS 2, *Share Based Payments*, a liability is recorded as compensation expense is recognized. The liability is revalued at each reporting date and at the date of settlement. These changes in fair value are recognized in profit or loss for the period. The types and timing of awards under this plan are described in further detail in note 0.

As compensation expense is recognized, contributed surplus is recorded until the restricted shares vest or stock options are exercised, at which time the appropriate common shares are then issued to the service providers and the contributed surplus is transferred to share capital.

(g) Revenue

Revenue from the sale of natural gas and liquids is recorded when the significant risks and rewards of ownership of the product is substantially transferred to the buyer.

(h) Finance expense

Finance expense comprises interest expense on bank indebtedness and the convertible debenture, and accretion of the discount on the decommissioning liability and convertible debenture.

(i) Income tax

Income tax expense or recovery comprises current and deferred income tax. Income tax expense or recovery is recognized in income or loss except to the extent that it relates to items recognized directly in shareholders' equity.

Current income tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to income tax payable in respect of previous years.

Deferred income tax is recognized using the liability method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred income tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination, and at the time of the transaction, affects neither accounting income nor taxable income. Deferred income tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date.

A deferred income tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred income tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized. Deferred income tax assets and liabilities are only offset when they are within the same legal entity and same tax jurisdiction. Deferred income tax assets and liabilities are presented as non-current.

(j) Net income (loss) per share

Basic net income (loss) per share is calculated by dividing the net income (loss) attributable to common shareholders of the Corporation by the weighted average number of common shares outstanding during the period. Diluted net income (loss) per share is determined by adjusting the net income (loss) attributable to common shareholders and the weighted average number of common shares outstanding for the effects of dilutive instruments such as restricted shares and stock options granted to service providers and convertible debentures, using the treasury stock method.

4. Significant accounting judgments, estimates and assumptions

The preparation of consolidated financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates, and differences could be material. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected. Significant estimates and judgments made in the preparation of the consolidated financial statements are outlined below.

(a) Reserves base

The natural gas and liquids development and production properties are depreciated on a units-of-production ("UOP") basis at a rate calculated by reference to proved and probable reserves determined in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" and incorporating the estimated future cost of developing and extracting those reserves. Proved plus probable reserves are determined using estimates of natural gas and liquids in place, recovery factors and future natural gas and liquids prices. Future development costs are estimated using assumptions as to number of wells required to produce the reserves, the cost of such wells and associated production facilities and other capital costs.

(b) Determination of cash generating unit

Management has determined there to be a single cash generating unit ("Glacier") on the basis of its ability to generate independent cash flows, similar reserve characteristics, geographical location, and shared infrastructure, namely a single processing plant owned by Advantage.

(c) Impairment indicators and calculation of impairment

At each reporting date, Advantage assesses whether or not there are circumstances that indicate a possibility that the carrying values of exploration and evaluation assets and property, plant and equipment are not recoverable, or impaired. Such circumstances include incidents of physical damage, deterioration of commodity prices, changes in the regulatory environment, or a reduction in estimates of proved and probable reserves.

When management judges that circumstances indicate potential impairment, property, plant and equipment are tested for impairment by comparing the carrying values to their recoverable amounts. The recoverable amounts of cash generating units are determined based on the higher of value-in-use calculations and fair values less costs of disposition. These calculations require the use of estimates and assumptions, that are subject to change as new information becomes available including information on future commodity prices, expected production volumes, quantities of reserves, discount rates, future development costs and operating costs (note 7 & 8).

(d) Decommissioning liability

Decommissioning costs will be incurred by the Corporation at the end of the operating life of some of the Corporation's facilities and properties. The ultimate decommissioning liability is uncertain and can vary in response to many factors including changes to relevant legal requirements, the emergence of new restoration techniques, experience at other production sites, or changes in the risk-free discount rate. The expected timing and amount of expenditure can also change in response to changes in reserves or changes in laws and regulations or their interpretation. As a result, there could be significant adjustments to the provisions established which would affect future financial results.

(e) Income taxes

Income tax laws and regulations are subject to change. Deferred tax liabilities that arise from temporary differences between recorded amounts on the statement of financial position and their respective tax bases will be payable in future periods. The amount of a deferred tax liability is subject to management's best estimate of when a temporary difference will reverse and expected changes in income tax rates. These estimates by nature involve significant measurement uncertainty.

5. Trade and other receivables

	December 31, 2014	December 31, 2013
Trade receivables	$ 19,607	$ 26,317
Receivables from joint venture partners	1,386	4,204
Other	981	1,495
	$ 21,974	**$ 32,016**

6. Investments

	December 31, 2014	December 31, 2013
Questfire Class B Shares	$ -	$ 3,750
Questfire Convertible Senior Secured Debenture	-	26,876
	$ -	**$ 30,626**

On March 26, 2014, Advantage entered into agreements whereby Questfire purchased both the Class B Shares and the Convertible Senior Secured Debenture for proceeds of $3.9 million and $13.6 million, respectively.

7. Exploration and evaluation assets

Balance at December 31, 2012	$ 2,381
Additions	6,977
Exploration and evaluation expense	(195)
Transferred to property, plant and equipment (note 8)	(146)
Transferred from assets held for sale	1,253
Balance at December 31, 2013	**$ 10,270**
Additions	3,237
Disposition of Longview (notes 3b and 24)	(2,335)
Exploration and evaluation expense	(53)
Transferred to property, plant and equipment (note 8)	(1,316)
Balance at December 31, 2014	**$ 9,803**

8. Property, plant and equipment

Cost	**Natural gas and liquids properties**	**Furniture and equipment**	**Total**
Balance at December 31, 2012	**$1,952,063**	**$5,240**	**$1,957,303**
Additions	188,451	-	188,451
Change in decommissioning liability (note 13)	(30,387)	-	(30,387)
Disposals	(5,876)	-	(5,876)
Transferred from exploration and evaluation assets (note 7)	146	-	146
Balance at December 31, 2013	**$ 2,104,397**	**$ 5,240**	**$ 2,109,637**
Additions	252,556	-	252,556
Change in decommissioning liability (note 13)	19,938	-	19,938
Disposition of Longview (notes 3b and 24)	(664,090)	-	(664,090)
Transferred from exploration and evaluation assets (note 7)	1,316	-	1,316
Balance at December 31, 2014	**$ 1,714,117**	**$ 5,240**	**$ 1,719,357**

Accumulated depreciation	**Natural gas and liquids properties**	**Furniture and equipment**	**Total**
Balance at December 31, 2012	**$ 349,092**	**$ 2,552**	**$ 351,644**
Depreciation	110,650	538	111,188
Disposals	(629)	-	(629)
Balance at December 31, 2013	**$ 459,113**	**$ 3,090**	**$ 462,203**
Depreciation	91,168	430	91,598
Disposition of Longview (notes 3b and 24)	(208,375)	-	(208,375)
Balance at December 31, 2014	**$ 341,906**	**$ 3,520**	**$ 345,426**

Net book value	**Natural gas and liquids properties**	**Furniture and equipment**	**Total**
At December 31, 2013	$ 1,645,284	$ 2,150	$ 1,647,434
At December 31, 2014	$ 1,372,211	$ 1,720	$ 1,373,931

During the year ended December 31, 2014, Advantage capitalized general and administrative expenditures directly related to development activities of $7.5 million (December 31, 2013 - $11.7 million).

Advantage included future development costs of $1.7 billion (December 31, 2013 – $2.1 billion) in property, plant and equipment costs subject to depreciation.

9. Related party transactions

Transactions between Advantage and Longview

Up until February 28, 2014, Advantage and Longview were bound by a Technical Services Agreement ("TSA"). Under the TSA, Advantage provided the necessary personnel and technical services to manage Longview's business and Longview reimbursed Advantage on a monthly basis for its share of administrative charges based on respective levels of production. All amounts paid were recorded as general and administrative expenses and measured at the fair value, which was the amount agreed upon by the transacting parties.

Advantage charged Longview $0.1 million during the period from January 1, 2014 to February 28, 2014 (year ended December 31, 2013 - $5.2 million) under the TSA. Dividends declared and paid or payable from Longview to Advantage during the period from January 1, 2014 to February 28, 2014 totaled $0.8 million (year ended December 31, 2013 - $12.5 million). All amounts due to Advantage from Longview were non-interest bearing in nature, and were incurred within the normal course of business. Upon closing of the Offering (note 3(b)), the TSA was terminated, and all intercompany balances were settled.

9. Related party transactions (continued)

Key management compensation

The compensation paid or payable to officers and directors is as follows:

	December 31, 2014	December 31, 2013
Salaries, director fees and short-term benefits	$ 2,297	$ 5,916
Share based compensation (1)	2,669	1,180
	$ 4,966	$ 7,096

(1) Represents the grant date fair value of restricted shares and stock options granted for the respective years.

As at December 31, 2014, there is a $2.3 million commitment (December 31, 2013 - $1.9 million) related to change of control or termination of employment of officers.

10. Financial risk management

Financial instruments of the Corporation include trade and other receivables, deposits, trade and other accrued liabilities, bank indebtedness, convertible debenture, derivative assets and liabilities, and performance incentive plan liability.

Trade and other receivables and deposits are classified as loans and receivables and measured at amortized cost. Trade and other accrued liabilities and bank indebtedness are all classified as financial liabilities at amortized cost. As at December 31, 2014, there were no significant differences between the carrying amounts reported on the Consolidated Statement of Financial Position and the estimated fair values of these financial instruments due to the short terms to maturity and the floating interest rate on the bank indebtedness.

The Corporation has a convertible debenture obligation outstanding, of which the liability component has been classified as a financial liability at amortized cost. The convertible debenture has fixed terms and interest rates resulting in fair values that will vary over time as market conditions change. As at December 31, 2014, the estimated fair value of the outstanding convertible debenture obligation was $86.3 million (December 31, 2013 - $86.7 million). The fair value of the liability component of the convertible debenture was determined based on the current public trading activity of the debenture.

Fair value is determined following a three level hierarchy:

Level 1: Quoted prices in active markets for identical assets and liabilities. The Corporation does not have any financial assets or liabilities that require level 1 inputs.

Level 2: Inputs other than quoted prices included within Level 1 that are observable, either directly or indirectly. Such inputs can be corroborated with other observable inputs for substantially the complete term of the contract. Derivative assets and liabilities and the performance incentive plan liability are measured at fair value on a recurring basis. For derivative assets and liabilities, pricing inputs include quoted forward prices for commodities, foreign exchange rates, volatility and risk-free rate discounting, all of which can be observed or corroborated in the marketplace. For the performance incentive plan liability, pricing inputs include estimates of forfeitures and risk-free rate discounting. The actual gains and losses realized on eventual cash settlement can vary materially due to subsequent fluctuations in commodity prices and share price as compared to the valuation assumptions.

Level 3: Under this level, fair value is determined using inputs that are not observable. Advantage has no assets or liabilities that use level 3 inputs.

10. Financial risk management (continued)

The Corporation's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production, and financing activities such as:

- credit risk;
- liquidity risk;
- price and currency risk; and
- interest rate risk.

(a) Credit risk

Credit risk is the risk of financial loss to the Corporation if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Corporation's receivables from joint venture partners, natural gas and liquids marketers and companies with whom we enter into hedging contracts. The maximum exposure to credit risk is as follows:

	December 31, 2014	December 31, 2013
Trade and other receivables	$ 21,974	$ 32,016
Deposits	1,210	1,548
Derivative asset	46,556	2,472
Questfire debenture	-	26,876
	$ 69,740	**$ 62,912**

Trade and other receivables, deposits, and derivative assets are subject to credit risk exposure and the carrying values reflect Management's assessment of the associated maximum exposure to such credit risk. Advantage mitigates such credit risk by closely monitoring significant counterparties and dealing with a broad selection of partners that diversify risk within the sector. The Corporation's deposits are due from the Alberta Provincial government and are viewed by Management as having minimal associated credit risk. To the extent that Advantage enters derivatives to manage commodity price risk, it may be subject to credit risk associated with counterparties with which it contracts. Credit risk is mitigated by entering into contracts with only stable, creditworthy parties and through frequent reviews of exposures to individual entities. In addition, the Corporation only enters into derivative contracts with major banks and international energy firms to further mitigate associated credit risk.

Substantially all of the Corporation's trade and other receivables are due from customers and joint operation partners concentrated in the Canadian oil and gas industry. As such, trade and other receivables are subject to normal industry credit risks. As at December 31, 2014, $0.6 million or 2.6% of trade and other receivables are outstanding for 90 days or more (December 31, 2013 - $0.9 million or 2.9% of trade and other receivables). The Corporation believes the entire balance is collectible, and in some instances has the ability to mitigate risk through withholding production or offsetting payables with the same parties. Management has not provided an allowance for doubtful accounts at December 31, 2014 or 2013.

The Corporation's most significant customer, a Canadian oil and natural gas marketer, accounts for $14.7 million of the trade and other receivables at December 31, 2014 (December 31, 2013 - $13.0 million).

10. Financial risk management (continued)

(b) Liquidity risk

The Corporation is subject to liquidity risk attributed from trade and other accrued liabilities, bank indebtedness, convertible debentures, and derivative liabilities. Trade and other accrued liabilities and derivative liabilities are primarily due within one year of the Consolidated Statement of Financial Position date and Advantage does not anticipate any problems in satisfying the obligations from cash provided by operating activities and the existing credit facilities. The Corporation's bank indebtedness is subject to $400 million credit facility agreements. Although the credit facilities are a source of liquidity risk, the facilities also mitigates liquidity risk by enabling Advantage to manage interim cash flow fluctuations. The terms of the credit facilities are such that they provide Advantage adequate flexibility to evaluate and assess liquidity issues if and when they arise. Additionally, the Corporation regularly monitors liquidity related to obligations by evaluating forecasted cash flows, optimal debt levels, capital spending activity, working capital requirements, and other potential cash expenditures. This continual financial assessment process further enables the Corporation to mitigate liquidity risk.

Advantage has a convertible debenture outstanding that matured on January 30, 2015 (note 12). Interest payments are made semi-annually with excess cash provided by operating activities. As the debenture becomes due, the Corporation can satisfy the obligation in cash or issue shares at a price determined in the applicable debenture agreement. This settlement alternative allows the Corporation to adequately manage liquidity, plan available cash resources and implement an optimal capital structure.

To the extent that Advantage enters derivatives to manage commodity price risk, it may be subject to liquidity risk as derivative liabilities become due. While the Corporation has elected not to follow hedge accounting, derivative instruments are not entered for speculative purposes and Management closely monitors existing commodity risk exposures. As such, liquidity risk is mitigated since any losses actually realized are subsidized by increased cash flows realized from the higher commodity price environment.

The timing of cash outflows relating to financial liabilities as at December 31, 2014 and 2013 are as follows:

December 31, 2014		**Less than one year**	**One to three years**	**Three to five years**	**Thereafter**	**Total**
Trade and other accrued liabilities		$ 81,741	$ -	$ -	$ -	$ 81,741
Bank indebtedness	- principal	-	110,332	-	-	110,332
	- interest [1]	6,847	3,283	-	-	10,130
Convertible debenture	- principal	86,250	-	-	-	86,250
	- interest	2,144	-	-	-	2,144
		$ 176,982	**$ 113,615**	**$ -**	**$ -**	**$290,597**

[1] Interest on bank indebtedness was calculated assuming conversion of the revolving credit facility to a one-year term facility.

December 31, 2013		**Less than one year**	**One to three years**	**Three to five years**	**Thereafter**	**Total**
Trade and other accrued liabilities		$ 93,893	$ -	$ -	$ -	$ 93,893
Derivative liability		8,340	1,183	-	-	9,523
Bank indebtedness	- principal	-	272,521	-	-	272,521
	- interest [1]	13,626	6,496	-	-	20,122
Convertible debenture	- principal	-	86,250	-	-	86,250
	- interest	4,313	2,156	-	-	6,469
		$ 120,172	**$ 368,606**	**$ -**	**$ -**	**$488,778**

[1] Interest on bank indebtedness was calculated assuming conversion of the revolving credit facility to a one-year term facility.

10. Financial risk management (continued)

The Corporation's bank indebtedness does not have specific maturity dates. It is governed by credit facility agreements with a syndicate of financial institutions (note 11). Under the terms of the agreements, the facilities are reviewed annually, with the next review scheduled in June 2015. The facilities are revolving and are extendible at each annual review for a further 364 day period at the option of the syndicate. If not extended, the credit facilities are converted at that time into one year term facilities, with the principal payable at the end of such one year terms. Management fully expects that the facilities will be extended at each annual review.

(c) Price and currency risk

Advantage's derivative assets and liabilities are subject to both price and currency risks as their fair values are based on assumptions including forward commodity prices and foreign exchange rates. The Corporation enters into non-financial derivatives to manage commodity price risk exposure relative to actual commodity production and does not utilize derivative instruments for speculative purposes. Changes in the price assumptions can have a significant effect on the fair value of the derivative assets and liabilities and thereby impact earnings. It is estimated that a 10% change in the forward natural gas prices used to calculate the fair value of the natural gas derivatives at December 31, 2014 would result in a $12.1 million change in net income for the year ended December 31, 2014.

As at December 31, 2014, the Corporation's natural gas hedging positions are summarized as follows:

Period	Average Production Hedged	Average Price AECO ($Cdn.)
Q1 2015 to Q4 2015	78.2 mmcf/d	$3.90/mcf
Q1 2016 to Q4 2016	56.9 mmcf/d	$3.93/mcf
Q1 2017	47.4 mmcf/d	$3.95/mcf

As at December 31, 2014, the fair value of the derivatives outstanding resulted in an asset of $46.6 million (December 31, 2013 – $2.5 million) and a liability of $Nil (December 31, 2013 – $9.5 million). The fair value of the commodity risk management derivatives have been allocated to current assets and liabilities on the basis of expected timing of cash settlement.

For the year ended December 31, 2014, $30.9 million was recognized in net income as a derivative gain (December 31, 2013 - $14.7 million derivative loss). The table below summarizes the realized and unrealized gains (losses) on derivatives recognized in net income (loss).

	Year ended December 31, 2014	Year ended December 31, 2013
Realized loss on derivatives	$ (14,028)	$ (3,936)
Unrealized gain (loss) on derivatives	44,941	(10,812)
	$ 30,913	**$ (14,748)**
From continuing operations	$ 35,236	$ (3,190)
From discontinued operations	(4,323)	(11,558)
	$ 30,913	**$ (14,748)**

(d) Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The interest charged on the outstanding bank indebtedness fluctuates with the interest rates posted by the lenders. The Corporation is exposed to interest rate risk and has not entered into any mitigating interest rate hedges or swaps. Had the borrowing rate been different by 100 basis points throughout the year ended December 31, 2014, net income (loss) and comprehensive income (loss) would have changed by $0.7 million (December 31, 2013 - $2.0 million) based on the average debt balance outstanding during the year.

10. Financial risk management (continued)

(e) Capital management

The Corporation manages its capital with the following objectives:

- To ensure sufficient financial flexibility to achieve the ongoing business objectives including replacement of production, funding of future growth opportunities, and pursuit of accretive acquisitions; and
- To maximize shareholder return through enhancing the share value.

Advantage monitors its capital structure and makes adjustments according to market conditions in an effort to meet its objectives given the current outlook of the business and industry in general. The capital structure of the Corporation is composed of working capital (excluding derivative assets and liabilities), bank indebtedness, convertible debentures, and share capital. Advantage may manage its capital structure by issuing new shares, repurchasing outstanding shares, obtaining additional financing either through bank indebtedness or convertible debenture issuances, refinancing current debt, issuing other financial or equity-based instruments, declaring a dividend, adjusting capital spending, or disposing of assets. The capital structure is reviewed by Management and the Board of Directors on an ongoing basis.

Advantage's capital structure as at December 31, 2014 and December 31, 2013 is as follows:

	December 31, 2014	December 31, 2013
Bank indebtedness (non-current) (note 11)	$ 109,970	$ 271,339
Working capital deficit (1)	57,264	58,520
Net debt	167,234	329,859
Convertible debentures maturity value (current)	86,250	86,250
Total debt	**$ 253,484**	**$ 416,109**
Shares outstanding (note 15)	170,067,650	168,382,838
Share closing market price ($/share)	$ 5.56	$ 4.61
Market capitalization (2)	945,576	776,245
Total capitalization	**$ 1,199,060**	**$ 1,192,354**

(1) Working capital deficit is a non-GAAP measure that includes trade and other receivables, prepaid expenses and deposits and trade and other accrued liabilities.

(2) Market capitalization is a non-GAAP measure calculated by multiplying shares outstanding by the closing market share price on the applicable date.

11. Bank indebtedness

	December 31, 2014	December 31, 2013
Revolving credit facility:		
Advantage	$ 110,332	$ 154,370
Longview	-	118,151
Discount on Bankers Acceptances and other fees	(362)	(1,182)
Balance, end of year	**$ 109,970**	**$ 271,339**

As at December 31, 2014, the Corporation had credit facilities (the "Credit Facilities") of $400 million. The Credit Facilities are comprised of a $20 million extendible revolving operating loan facility from one financial institution and $380 million of extendible revolving loan facilities from a syndicate of financial institutions. Amounts borrowed under the Credit Facilities bear interest at a floating rate based on the applicable Canadian prime rate, US base rate, LIBOR rate or bankers' acceptance rate plus between 1.00% and 3.50% depending on the type of borrowing and the Corporation's debt to cash flow ratio. The Credit Facilities are collateralized by a $1 billion floating charge demand debenture covering all assets. The amounts available to the Corporation from time to time under the Credit Facilities are based upon the borrowing base determined semi-annually by the lenders. The revolving period for the Credit Facilities will end in June 2015 unless extended at the option of the syndicate for a further 364 day period. If the Credit Facilities are not extended, they will convert to a non-revolving term facility due 365 days after the last day of the revolving period. The Credit Facilities prohibit the Corporation from entering into any derivative contract where the term of such contract exceeds four years. Further, the aggregate of such contracts cannot hedge greater than 65% of total estimated natural gas and liquids production over three years and 50% over the fourth year. The Credit Facilities contain standard commercial covenants for credit facilities of this nature. The only financial covenant is a requirement for the Corporation to maintain a minimum cash flow to interest expense ratio of 3.5:1, determined on a rolling four-quarter basis. These covenants were met at December 31, 2014 and 2013. Breach of any covenant will result in an event of default in which case the Corporation has 20 days to remedy such default. If the default is not remedied or waived, and if required by the lenders, the administrative agent of the lenders has the option to declare all obligations under the credit facilities to be immediately due and payable without further demand, presentation, protest, days of grace, or notice of any kind. Interest payments under the debentures are subordinated to the repayment of any amounts owing under the Credit Facilities and are not permitted if the Corporation is in default of such Credit Facilities or if the amount of outstanding indebtedness under such facilities exceeds the then existing current borrowing base. For the year ended December 31, 2014, the average effective interest rate on the outstanding amounts under the facilities was approximately 3.8% (December 31, 2013 – 5.0%). Advantage has $2.5 million letters of credit issued and outstanding at December 31, 2014 (December 31, 2013 - $Nil).

12. Convertible debenture

The convertible unsecured subordinated debenture pays an annual coupon of 5%, paid semi-annually on January 31st and July 31st of each year and is convertible at the option of the holder into shares of Advantage at the applicable conversion price per share plus accrued and unpaid interest. The details of the convertible debenture including fair market values initially assigned and issuance costs are as follows:

Trading symbol	AAV.DBH
Issue date	Dec. 31, 2009
Maturity date	Jan. 30, 2015
Conversion price	$ 8.60
Liability component	$ 73,019
Equity component	13,231
Gross proceeds	86,250
Issuance costs	(3,735)
Net proceeds	**$ 82,515**

The convertible debenture is redeemable at the option of the Corporation, upon providing appropriate advance notification as per the debenture indenture. Redemption can only occur during the period after January 31, 2013 and on or before January 30, 2015, provided that the Current Market Price exceeds 125% of the Conversion Price. The redemption price is $1,000 per debenture, plus accrued and unpaid interest.

The balance of the convertible debenture outstanding at December 31, 2014 and changes in the liability and equity components during the years ended December 31, 2014 and 2013 are as follows:

	5.00%
Trading symbol	AAV.DBH
Debentures outstanding	$ 86,250
Liability component:	
Balance at December 31, 2012	**79,108**
Accretion of discount	3,346
Balance at December 31, 2013	**$ 82,454**
Accretion of discount	3,487
Balance at December 31, 2014	**$ 85,941**
Equity component:	
Balance at December 31, 2013	**$ 8,348**
Balance at December 31, 2014	**$ 8,348**

There were no convertible debenture conversions during the years ended December 31, 2014 and 2013. On January 30, 2015, both the principal and final interest payment were settled with cash drawn from the credit facility, with the exception of $0.01 million, which was converted to 1,162 common shares.

13. Decommissioning liability

The Corporation's decommissioning liability results from net ownership interests in natural gas and liquids assets including well sites, gathering systems and processing facilities, all of which will require future costs of decommissioning under environmental legislation. These costs are expected to be incurred between 2015 and 2074. A risk-free rate of 2.33% (December 31, 2013 – 3.20%) and an inflation factor of 2% (December 31, 2013 – 2%) were used to calculate the fair value of the decommissioning liability at December 31, 2014. A reconciliation of the decommissioning liability is provided below:

	Year ended December 31, 2014	Year ended December 31, 2013
Balance, beginning of year	$ 100,616	$ 126,224
Accretion expense	1,364	4,587
Liabilities incurred	4,218	3,908
Change in estimates	683	1,335
Effect of change in risk-free rate	15,037	(35,630)
Property dispositions	-	(1,419)
Liabilities settled	(482)	(3,098)
Disposition of Longview (note 3b and 24)	(72,558)	-
	48,878	95,907
Transferred from assets held for sale	-	4,709
Balance, end of year	**$ 48,878**	**$ 100,616**

14. Income taxes

The provision for income taxes is as follows:

	Year ended December 31, 2014	Year ended December 31, 2013
Current income tax expense	$ -	$ -
Deferred income tax expense (recovery)	30,393	(1,622)
Income tax expense (recovery)	$ 30,393	$ (1,622)

The provision for income taxes varies from the amount that would be computed by applying the combined federal and provincial income tax rates for the following reasons:

	Year ended December 31, 2014	Year ended December 31, 2013
Income (loss) before taxes from continuing operations	$ 104,990	$ (9,919)
Combined federal and provincial income tax rates	25.00%	25.00%
Expected income tax expense (recovery)	26,248	(2,480)
Increase (decrease) in income taxes resulting from:		
Non-deductible share based compensation	823	1,987
Change in estimated pool balances	-	(2,350)
Unrecognized deferred tax asset on sale of Questfire Debenture	3,458	-
Difference between current and expected tax rates	(136)	1,221
	$ 30,393	$ (1,622)
Effective tax rate	28.95%	16.35%

The movement in deferred income tax liabilities and assets without taking into consideration the offsetting of balances within the same tax jurisdiction is as follows:

Deferred income tax liability	Property, plant and equipment	Derivative asset/liability	Total
Balance at December 31, 2012	$ 237,246	$ 267	$ 237,513
Charged (credited) to income	(18,807)	(2,058)	(20,865)
Balance at December 31, 2013	218,439	(1,791)	216,648
Charged (credited) to income	10,586	13,430	24,016
Balance at December 31, 2014	$ 229,025	$ 11,639	$ 240,664

Deferred income tax asset	Decommissioning liability	Non-capital losses	Other	Total
Balance at December 31, 2012	$ (66,217)	$ (204,147)	$ (5,414)	$ (275,778)
Charged (credited) to income	40,594	(11,422)	(6,105)	23,067
Balance at December 31, 2013	(25,623)	(215,569)	(11,519)	(252,711)
Charged (credited) to income	13,320	31,956	170	45,446
Balance at December 31, 2014	$ (12,303)	$ (183,613)	$ (11,349)	$ (207,265)

Net deferred income tax liability (asset)	Longview	Advantage	Total
Balance at December 31, 2012	$ (42,893)	$ 4,628	$ (38,265)
Charged (credited) to income	3,824	(1,622)	2,202
Balance at December 31, 2013	(39,069)	3,006	(36,063)
Charged (credited) to income	39,069	30,393	69,462
Balance at December 31, 2014	$ -	$ 33,399	$ 33,399

The estimated tax pools available at December 31, 2014 are as follows:

Canadian development expenses	$ 219,133
Canadian exploration expenses	65,944
Canadian oil and gas property expenses	2,907
Non-capital losses	734,455
Capital losses	157,869
Undepreciated capital cost	168,869
Other	10,122
	$ 1,359,299

The non-capital loss carry forward balances above expire no earlier than 2023.

A deferred tax asset has not been recognized for capital losses realized in the amount of $158 million (December 31, 2013 – $11 million). Recognition is dependent on the realization of future taxable capital gains.

15. Share capital

(a) Authorized

The Corporation is authorized to issue an unlimited number of shares without nominal or par value.

(b) Issued

	Common Shares	Amount
Balance at December 31, 2012 and December 31, 2013	168,382,838	$ 2,229,598
Share based compensation (note 17)	1,684,812	5,361
Balance at December 31, 2014	170,067,650	$ 2,234,959

16. Net income (loss) per share attributable to Advantage shareholders

The calculations of basic and diluted net income (loss) per share are derived from both net income (loss) attributable to Advantage common shareholders and weighted average shares outstanding, calculated as follows:

	Year ended December 31, 2014	Year ended December 31, 2013
Net income (loss) attributable to Advantage shareholders		
Basic and diluted - continuing operations	$ 74,597	$ (8,297)
Basic and diluted - discontinued operations	(58,894)	4,915
Basic and diluted	$ 15,703	$ (3,382)
Weighted average shares outstanding		
Basic	169,482,394	168,382,838
Stock Option Plan	1,317,671	1,445,884
Diluted	170,800,065	169,828,722

The calculation of diluted net income (loss) per share for the years ended December 31, 2014 and 2013 excludes the convertible debenture, as its impact would be anti-dilutive. Total weighted average shares issuable in exchange for the convertible debenture excluded from the diluted net income (loss) per share calculation for the years ended December 31, 2014 and 2013 was 10,029,070 shares. As at December 31, 2014 and 2013, the total convertible debenture outstanding was convertible to 10,029,070 shares.

17. Share based compensation

(a) Stock option plan

Under the Stock Option Plan, service providers are granted options with exercise prices that approximate the market price of common shares at the date of grant. Share based compensation costs of the Stock Option Plan are determined using a Black-Scholes valuation model, using weighted average assumptions as follows:

Volatility	41%
Expected forfeiture rate	0.85%
Dividend rate	0%
Risk-free rate	1.07%

Volatility is based on historical stock prices at the close-of-trade-day over a historical time period.

The following tables summarize information about changes in stock options outstanding at December 31, 2014:

	Stock Options	Weighted-Average Exercise Price
Balance at December 31, 2012	15,977,883	$ 3.67
Expired	(1,994,658)	3.67
Exercised	(1,994,641)	3.67
Granted	3,804,675	3.69
Forfeited/cancelled	(2,732,416)	3.68
Balance at December 31, 2013	13,060,843	$ 3.68
Exercised	(7,435,115)	3.67
Granted	3,777,255	5.00
Forfeited/cancelled	(4,258,307)	3.70
Balance at December 31, 2014	5,144,676	$ 4.63

	Stock Options Outstanding			Stock Options Exercisable	
Range of Exercise Price	Number of Stock Options Outstanding	Weighted Average Remaining Contractual Life - Years	Weighted Average Exercise Price	Number of Stock Options Exercisable	Weighted Average Exercise Price
$3.69 - $4.43	3,674,727	1.35	$ 4.14	726,949	$ 3.69
$4.44 - $6.34	1,469,949	4.29	5.87	-	-
$3.69 - $6.34	5,144,676	2.19	$ 4.63	726,949	$ 3.69

17. Share based compensation (continued)

(b) Performance Incentive Plan

Under the Performance Incentive Plan, service providers can be granted two types of Incentive Awards: Restricted Awards and Performance Awards. A Restricted Award is a grant denominated in a fixed number of common shares which generally vests 1/3 on the first anniversary of the grant date, 1/3 on the second anniversary, and 1/3 on the third anniversary. A Performance Award is a grant denominated in a fixed number of common shares which vests on the third anniversary of the grant date. Performance Award grants are multiplied by a Payout Multiplier. The Payout Multiplier is a number between zero (0) and two (2), and is determined based on an equal weighting of three Corporate Performance Measures: Relative Total Shareholder Return, Annual Cash Flow Per Share and Relative Cost Structure.

As at December 31, 2014, no Restricted Awards have been granted.

The following table is a continuity of Performance Awards:

Balance at December 31, 2012 and 2013	-
Granted	409,702
Forfeited	(3,560)
Balance at December 31, 2014	406,142

Share based compensation recognized by plan for the years ended December 31, 2014 and 2013 are as follows:

	Year ended December 31 2014	Year ended December 31 2013
RSPIP [1]	$ 1,058	$ 420
Stock Option Plan	3,265	7,874
Performance Incentive Plan	512	-
Total share based compensation	4,835	8,294
Capitalized	(2,016)	(2,838)
Net share based compensation expense	**$ 2,819**	**$ 5,456**
From continuing operations	$ 2,153	$ 5,180
From discontinued operations	666	276
	$ 2,819	**$ 5,456**

[1] Relates solely to discontinued operations

18. Natural gas and liquids sales

	Year ended December 31 2014	Year ended December 31 2013
Natural gas sales	$ 212,579	$ 134,878
Crude oil and natural gas liquids sales	27,789	154,864
Total natural gas and liquids sales	**$ 240,368**	**$ 289,742**
From continuing operations	$ 215,653	$ 140,090
From discontinued operations	24,715	149,652
	$ 240,368	**$ 289,742**

19. General and administrative expense ("G&A")

	Year ended December 31	
	2014	**2013**
Salaries and benefits	$ 8,786	$ 22,877
Share based compensation (note 17)	4,835	8,294
Office rent	1,173	2,109
Other	4,126	5,863
Total G&A	**18,920**	**39,143**
Capitalized (note 8)	(7,450)	(11,735)
Net G&A	**$ 11,470**	**$ 27,408**
From continuing operations	$ 9,579	$ 24,426
From discontinued operations	1,891	2,982
	$ 11,470	**$ 27,408**

20. Finance expense

	Year ended December 31	
	2014	**2013**
Interest on bank indebtedness (note 11)	$ 6,817	$ 13,305
Interest on convertible debenture (note 12)	4,313	4,313
Accretion on convertible debenture (note 12)	3,487	3,346
Accretion of decomissioning liability (note 13)	1,364	5,169
Total finance expense	**$ 15,981**	**$ 26,133**
From continuing operations	$ 14,792	$ 18,225
From discontinued operations	1,189	7,908
	$ 15,981	**$ 26,133**

21. Other income (expenses)

	Year ended December 31	
	2014	**2013**
Interest income - Questfire Debenture (note 6)	$ 455	$ 1,312
Accretion income - Questfire Debenture (note 6)	557	1,516
Loss on disposition of Questfire Debenture (note 6)	(13,833)	-
Unrealized gain (loss) - Questfire Class B Shares	150	(900)
Loss on sale of assets	(1,489)	(8,154)
Miscellaneous income	3,633	1,102
Total other income (expenses)	**$ (10,527)**	**$ (5,124)**
From continuing operations	$ (10,527)	$ (3,979)
From discontinued operations	-	(1,145)
	$ (10,527)	**$ (5,124)**

22. Supplementary cash flow information – continuing operations

Changes in non-cash working capital is comprised of:

	Year ended December 31 2014	Year ended December 31 2013
Source (use) of cash:		
Trade and other receivables	$ (4,876)	$ 1,207
Prepaid expenses and deposits	159	1,835
Trade and other accrued liabilities	11,525	10,526
	$ 6,808	$ 13,568
Related to operating activities	$ (3,924)	$ 6,623
Related to financing activities	1,311	206
Related to investing activities	9,421	6,739
	$ 6,808	$ 13,568

23. Commitments

Advantage has several lease commitments relating to office buildings and transportation commitments. The estimated remaining annual minimum operating lease payments are as follows:

	December 31 2014	December 31 2013
2014	-	13,260
2015	18,220	4,305
2016	20,485	-
2017	19,511	-
2018	17,414	-
2019	15,677	-
2020 and thereafter	33,386	-
Total commitments	**$ 124,693**	**$ 17,565**

24. Discontinued operations

The Corporation was previously comprised of two operating segments: Advantage Oil & Gas Ltd. ("Advantage") and Longview Oil Corp. ("Longview"). Advantage develops and operates a natural gas focused property in Alberta. Longview developed and operated primarily conventional oil and natural gas liquids focused properties in Alberta and Saskatchewan. On February 28, 2014, the Corporation discontinued the Longview segment by selling its investment in Longview pursuant to the Offering (note 3(b)).

Results of the discontinued Longview segment are as follows:

(thousands of Canadian dollars)	Year ended December 31 2014 [(1)]	2013
Petroleum and natural gas sales	$ 24,715	$ 149,652
Less: royalties	(4,108)	(26,297)
Petroleum and natural gas revenue	20,607	123,355
Operating expense	(7,022)	(45,799)
General and administrative expense	(1,891)	(2,982)
Depreciation expense	(6,138)	(39,048)
Finance expense	(1,189)	(7,908)
Losses on derivatives	(4,323)	(11,558)
Exploration and evaluation expense	-	(195)
Other income (expenses)	-	(1,145)
Non-controlling interest	85	(5,981)
Income before taxes from discontinued operations	**129**	**8,739**
Income tax expense	(198)	(3,824)
Income (loss) from discontinued operations	**(69)**	**4,915**
Loss on disposition of Longview	(58,825)	-
Net income (loss) from discontinued operations	**$ (58,894)**	**$ 4,915**

[(1)] Results from January 1, 2014 to February 28, 2014

Cash flows of the discontinued Longview segment are as follows:

(thousands of Canadian dollars)	Year ended December 31 2014	2013
Cash flow from operating activities	$ 12,434	$ 65,651
Cash flow from (used in) financing activities	435	(15,217)
Cash flow from (used in) investing activities	78,976	(37,743)

Exhibit 99.3

CONSOLIDATED MANAGEMENT'S DISCUSSION & ANALYSIS

The following Management's Discussion and Analysis ("MD&A"), dated as of March 25, 2015, provides a detailed explanation of the consolidated financial and operating results of Advantage Oil & Gas Ltd. ("Advantage", the "Corporation", "us", "we" or "our") for the three months and year ended December 31, 2014 and should be read in conjunction with the December 31, 2014 audited consolidated financial statements. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"), representing generally accepted accounting principles ("GAAP") for publicly accountable enterprises in Canada. All references in the MD&A and consolidated financial statements are to Canadian dollars unless otherwise indicated. The term "boe" or barrels of oil equivalent and "mcfe" or thousand cubic feet equivalent may be misleading, particularly if used in isolation. A boe or mcfe conversion ratio of six thousand cubic feet of natural gas equivalent to one barrel of oil (6 mcf: 1 bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Forward-Looking Information

This MD&A contains certain forward-looking statements, which are based on our current internal expectations, estimates, projections, assumptions and beliefs. 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", "would" and similar or related expressions. These statements are not guarantees of future performance.

In particular, forward-looking statements included in this MD&A include, but are not limited to, expected average production levels until July 2015 and anticipated increase to production levels in July, 2015; effect of commodity prices on the Corporation's financial results, condition and performance; industry conditions, including effect of changes in commodity prices, weather and general economic conditions on the crude oil and natural gas industry and demand for crude oil and natural gas; the Corporation's hedging activities; effect of commodity price risk management activities on the Corporation, including cash flows and sales; terms of the Corporation's derivative contracts, including the timing of settlement of such contracts; effect of fluctuations in commodity prices as compared to valuation assumptions on actual gains or losses realized on cash settlement of derivatives; average royalty rates and the impact of well depths, well production rates, commodity prices and gas cost allowance on average corporate royalty rates; projected royalty rates, including the estimated royalty rate for the life of a Glacier Montney horizontal well; expected timing of rig release, service and receipt of regulatory approvals for Advantage's water disposal well and the effect of such water disposal well on water handling capacity at Glacier and third party costs; terms of the Corporation's equity compensation plans; estimated tax pools at December 31, 2014; terms of the Corporation's credit facilities, including timing of next review of the credit facilities; the Corporation's expectations regarding extension of Advantage's credit facilities at each annual review, effect of revisions or changes in reserve estimates and commodity prices on the borrowing base, and limitations on the utilization of hedging contracts; future commitments and contractual obligations; the Corporation's strategy for managing its capital structure, including the use of equity and debt financing arrangements, adjusting capital spending, disposing of assets and the use of financial and operational forecasting processes to facilitate management of the Corporation's capital structure; the timing of reviews of capital structure and forecast information by management and the Board; effect of the Corporation's continual financial assessment processes on the Corporation's ability to mitigate risks; the Corporation's plans to fund the majority of its capital expenditures for the year ended December 31, 2015 from funds from operations; the Corporation's forecasted debt to trailing funds from operations ratio; the Corporation's ability to satisfy all liabilities and commitments, including a working capital deficit, and meet future obligations as they become due; Advantage's expectation that its current inventory of wells can maintain production at the levels disclosed herein through to completion of the Corporation's plant expansion at Glacier; anticipated timing of completion of the Corporation's plant expansion at Glacier; targeted level of production from Advantage's Phase VII program and the anticipated timing of achievement thereof; the Corporation's intentions to monitor debt levels to ensure an optimal mix of financing and cost of capital to provide a return to the Corporation's shareholders; Advantage's focus on development of the natural gas resource play at Glacier, including the anticipated timing of completion of the various phases of Advantage's development program at Glacier and expected timing of well completions; and the statements under "critical accounting estimates" in this MD&A. In addition, statements relating to "reserves" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves described can be profitably produced in the future.

These forward-looking statements involve substantial known and unknown risks and uncertainties, many of which are beyond our control, including, but not limited to, changes in general economic, market and business conditions; stock market volatility; changes to legislation and regulations and how they are interpreted and enforced; changes to investment eligibility or investment criteria; our ability to comply with current and future environmental or other laws; actions by governmental or regulatory authorities including increasing taxes, changes in investment or other regulations; changes in tax laws, royalty regimes and incentive programs relating to the oil and gas industry; the effect of acquisitions; our success at acquisition, exploitation and development of reserves; unexpected drilling results; changes in commodity prices, currency exchange rates, capital expenditures, reserves or reserves estimates and debt service requirements; the occurrence of unexpected events involved in the exploration for, and the operation and development of, oil and gas properties; hazards such as fire, explosion, blowouts, cratering, and spills, each of which could result in substantial damage to wells, production facilities, other property and the environment or in personal injury; changes or fluctuations in production levels; individual well productivity; delays in anticipated timing of drilling and completion of wells; failure to extend the credit facilities at each annual review; competition from other producers; the lack of availability of qualified personnel or management; ability to access sufficient capital from internal and external sources; credit risk; and the risks and uncertainties described in the Corporation's Annual Information Form which is available at www.sedar.com and www.advantageog.com. Readers are also referred to risk factors described in other documents Advantage files with Canadian securities authorities.

With respect to forward-looking statements contained in this MD&A, in addition to other assumptions identified herein, Advantage has made assumptions regarding, but not limited to: conditions in general economic and financial markets; effects of regulation by governmental agencies; receipt of required regulatory approvals; current commodity prices and royalty regimes; future exchange rates; royalty rates; future operating costs; availability of skilled labour; availability of drilling and related equipment; timing and amount of capital expenditures; the impact of increasing competition; the price of crude oil and natural gas; that the Corporation will have sufficient cash flow, debt or equity sources or other financial resources required to fund its capital and operating expenditures and requirements as needed; that the Corporation's conduct and results of operations will be consistent with its expectations; that the Corporation will have the ability to develop the Corporation's crude oil and natural gas properties in the manner currently contemplated; that current or, where applicable, proposed assumed industry conditions, laws and regulations will continue in effect or as anticipated as described herein; and that the estimates of the Corporation's production, reserves and resources volumes and the assumptions related thereto (including commodity prices and development costs) are accurate in all material respects.

Management has included the above summary of assumptions and risks related to forward-looking information provided in this MD&A in order to provide shareholders with a more complete perspective on Advantage's future operations and such information may not be appropriate for other purposes. Advantage'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 that Advantage will derive there from. Readers are cautioned that the foregoing lists of factors are not exhaustive. These forward-looking statements are made as of the date of this MD&A and Advantage disclaims any intent or obligation to update publicly any forward-looking statements, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws.

Disposition of Longview and Discontinued Operations

Advantage owned 21,150,010 common shares of Longview Oil Corp. ("Longview") prior to February 28, 2014, representing an interest of approximately 45.1% of Longview. Since Advantage held the single largest ownership interest of Longview and other ownership interests were comparatively dispersed, Advantage was considered to control Longview. Accordingly, prior to February 28, 2014, the financial and operating results of Longview were consolidated 100% within Advantage and non-controlling interest was recognized which represented Longview's independent shareholders 54.9% ownership interest in the net assets and income of Longview. On February 28, 2014, Advantage sold the 21,150,010 common shares of Longview at a price of $4.45 per share and received net proceeds of $90.2 million, all of which were used to reduce existing bank indebtedness. Concurrently, Advantage derecognized all assets and liabilities of Longview from the consolidated statement of financial position and ceased to consolidate Longview subsequent to February 28, 2014.

Given that the Longview legal entity was an operating segment, the financial results for the Advantage legal entity are presented as "continuing operations" and for the Longview legal entity are presented as "discontinued operations" for all periods in the consolidated financial statements, as required by IFRS. This presentation has been consistently applied throughout this MD&A on a similar basis with the term "continuing operations" referring to the Advantage legal entity and "discontinued operations" referring to the Longview legal entity.

Non-GAAP Measures

The Corporation discloses several financial measures in the MD&A that do not have any standardized meaning prescribed under GAAP. These financial measures include funds from operations and cash netbacks. Management believes that these financial measures are useful supplemental information to analyze operating performance and provide an indication of the results generated by the Corporation's principal business activities. Investors should be cautioned that these measures should not be construed as an alternative to net income, comprehensive income, and cash provided by operating activities or other measures of financial performance as determined in accordance with GAAP. Advantage's method of calculating these measures may differ from other companies, and accordingly, they may not be comparable to similar measures used by other companies.

Funds from operations, as presented, is based on cash provided by operating activities, before expenditures on decommissioning liability and changes in non-cash working capital, reduced for finance expense excluding accretion. Management believes these adjustments to cash provided by operating activities increase comparability between reporting periods. Cash netbacks are dependent on the determination of funds from operations and include the primary cash sales and expenses on a per mcfe basis that comprise funds from operations. Funds from operations reconciled to cash provided by operating activities is as follows:

	Three months ended December 31			Year ended December 31		
($000)	**2014**	**2013**	**% change**	**2014**	**2013**	**% change**
Cash provided by operating activities - continuing operations	$ 48,218	$ 42,488	13%	$ 169,907	$ 99,366	71%
Expenditures on decommissioning liability	367	1,152	(68)%	446	4,664	(90)%
Changes in non-cash working capital	(6,901)	(16,644)	(59)%	3,924	(6,623)	(159)%
Finance expense [(1)]	(2,502)	(3,174)	(21)%	(10,267)	(12,097)	(15)%
Funds from operations - continuing operations	**$ 39,182**	**$ 23,822**	**64%**	**164,010**	**85,310**	**92%**
Funds from operations - discontinued operations	-	13,740	(100)%	10,019	63,195	(84)%
Funds from operations	**$ 39,182**	**$ 37,562**	**4%**	**$ 174,029**	**$ 148,505**	**17%**

[(1)] Finance expense excludes non-cash accretion expense.

FINANCIAL AND OPERATING REVIEW – CONTINUING OPERATIONS

Overview

	Three months ended December 31				Year ended December 31			
	2014		2013		2014		2013	
	($000)	per mcfe	($000)	per mcfe	($000)	per mcfe	($000)	per mcfe
Natural gas and liquids sales	$ 47,186	$ 3.82	$ 32,546	$ 3.25	$ 215,653	$ 4.49	$ 140,090	$ 3.28
Realized gains (losses) on derivatives	(777)	(0.06)	1,758	0.18	(12,550)	(0.26)	2,853	0.07
Royalties	(2,209)	(0.18)	(1,523)	(0.15)	(10,076)	(0.21)	(7,534)	(0.18)
Operating expense	(4,184)	(0.34)	(2,772)	(0.28)	(15,412)	(0.32)	(20,515)	(0.48)
Operating income and operating netbacks	**40,016**	**3.24**	**30,009**	**3.00**	**177,615**	**3.70**	**114,894**	**2.69**
General and administrative (1)	(1,371)	(0.11)	(3,932)	(0.39)	(7,426)	(0.15)	(19,246)	(0.45)
Finance expense (2)	(2,502)	(0.20)	(3,174)	(0.32)	(10,267)	(0.21)	(12,097)	(0.28)
Other income (3)	3,039	0.25	919	0.09	4,088	0.09	1,759	0.04
Funds from operations and cash netbacks	**$ 39,182**	**$ 3.18**	**$ 23,822**	**$ 2.38**	**$ 164,010**	**$ 3.43**	**$ 85,310**	**$ 2.00**
Per basic weighted average share	**$ 0.23**		**$ 0.14**		**$ 0.97**		**$ 0.51**	

(1) General and administrative expense excludes share based compensation.
(2) Finance expense excludes non-cash accretion expense.
(3) Other income excludes non-cash other income.

For the three months ended December 31, 2014, Advantage realized a 64% increase in funds from operations to $39.2 million and a 34% increase in cash netbacks to $3.18 per mcfe, as compared to the fourth quarter of 2013. Funds from operations for the year ended December 31, 2014, increased 92% to $164.0 million and cash netbacks increased 72% to $3.43 per mcfe, as compared to the same period of 2013. On a per share basis, funds from operations increased 64% and 90% to $0.23 and $0.97 for the three months and year ended December 31, 2014, respectively. The increased funds from operations and cash netbacks were driven by Glacier production growth, higher natural gas prices and a lower total cash cost structure. Glacier production during the three months and year ended December 31, 2014 was 23% and 25% higher than the same periods of 2013, as we continue to execute on our multi-year development plan. AECO daily prices during the three months and year ended December 31, 2014 was 2% and 41% higher than the same periods of 2013. We have also achieved an industry leading low cost structure whereby total cash costs for the year ended December 31, 2014, including royalties, operating expense, general and administrative expense, and finance expense have been reduced by 36% to $0.89 per mcfe as compared to 2013. The lower total cash cost structure resulted from transforming Advantage into a pure play Montney producer with a single focus on development of our Glacier, Alberta area.

Advantage has disposed of substantially all non-core assets to focus on continued development of its core Glacier Montney natural gas asset. Net cash proceeds received from all disposition transactions were used to reduce outstanding bank indebtedness. The disposition transactions have had a pervasive impact on the financial and operating results and financial position of Advantage such that historical financial and operating performance may not be indicative of actual future performance.

Natural Gas and Liquids Sales and Hedging

	Three months ended December 31			Year ended December 31		
($000)	**2014**	**2013**	**% change**	**2014**	**2013**	**% change**
Natural gas sales	$ 46,446	$ 31,984	45%	$ 210,444	$ 126,038	67%
Realized gains (losses) on derivatives	(777)	1,758	(144)%	(12,550)	2,837	(542)%
Natural gas sales including hedging	45,669	33,742	35%	197,894	128,875	54%
Liquids sales	740	562	32%	5,209	14,052	(63)%
Realized gain on derivative	-	-	-%	-	16	(100)%
Liquids sales including hedging	740	562	32%	5,209	14,068	(63)%
Total (1)	**$ 46,409**	**$ 34,304**	**35%**	**$ 203,103**	**$ 142,943**	**42%**

(1) Total excludes unrealized derivative gains and losses.

Total sales excluding hedging for the three months ended December 31, 2014 was $47.2 million, an increase of $14.6 million or 45%, and for the year ended December 31, 2014 was $215.7 million, an increase of $75.6 million or 54%, when compared to the same periods of 2013. The increase in sales has been attributable to improved natural gas prices and higher natural gas production.

Production

	Three months ended December 31			Year ended December 31		
	2014	**2013**	**% change**	**2014**	**2013**	**% change**
Natural gas (mcf/d)	133,433	108,260	23%	130,627	113,947	15%
Liquids (bbls/d)	113	79	43%	159	507	(69)%
Total - mcfe/d	**134,111**	**108,734**	**23%**	**131,581**	**116,989**	**12%**
- boe/d	**22,352**	**18,122**	**23%**	**21,930**	**19,498**	**12%**
Natural gas (%)	99%	100%		99%	97%	
Liquids (%)	1%	-%		1%	3%	

Production for the fourth quarter of 2014 increased 23% as compared to the fourth quarter of 2013. Glacier production increased 25% during the year ended December 31, 2014 as compared to 2013 but was partially offset by non-core conventional asset sales of approximately 12 mmcfe/d which closed in April 2013. We expect production to average approximately 130 mmcfe/d to 135 mmcfe/d until July 2015 when production is scheduled to increase to 183 mmcfe/d according to our 2015 Guidance and Development Plan Update news release, issued February 17, 2015.

Commodity Prices and Marketing

	Three months ended December 31 2014	Three months ended December 31 2013	% change	Year ended December 31 2014	Year ended December 31 2013	% change
Average Realized Pricing						
Natural gas, excluding hedging ($/mcf)	$ 3.78	$ 3.21	18%	$ 4.41	$ 3.03	46%
Natural gas, including hedging ($/mcf)	$ 3.72	$ 3.39	10%	$ 4.15	$ 3.10	34%
Liquids, including hedging ($/bbl)	$ 71.35	$ 77.01	(7)%	$ 89.84	$ 76.01	18%
Benchmark Prices						
AECO daily ($/mcf)	$ 3.61	$ 3.52	2%	$ 4.47	$ 3.18	41%
NYMEX ($US/mmbtu)	$ 3.95	$ 3.63	9%	$ 4.38	$ 3.67	19%
Edmonton Light ($/bbl)	$ 75.54	$ 86.88	(13)%	$ 94.50	$ 93.43	1%

Advantage's current production from Glacier is approximately 99% natural gas. Realized natural gas prices, excluding hedging, increased significantly as compared to 2013, corresponding to the increase in AECO prices. Natural gas prices remained low throughout much of 2013 due to a stronger supply to demand situation. Prices improved dramatically during early 2014 as a result of an extremely cold 2013/2014 winter that increased demand and reduced North American storage levels well below the five-year average. During the second half of 2014, natural gas prices decreased due to the continued strength of U.S. storage injections caused by record supply levels and reduced demand from a moderate 2014 summer followed by a mild 2014/2015 winter. Advantage has hedged approximately 57% of forecast production, net of royalties, for calendar 2015 at an average natural gas price of $3.86/mcf to support our Glacier development plan.

Commodity Price Risk

The Corporation's financial results and condition will be dependent on the prices received for natural gas production. Natural gas prices have fluctuated widely and are determined by supply and demand factors, including weather, and general economic conditions in natural gas consuming and producing regions throughout North America. Management has been proactive in entering into derivatives for the purpose of hedging and has mitigated commodity price risk by entering natural gas hedging contracts to March 31, 2017 in support of our Glacier multi-year development plan. Our Credit Facilities allow Advantage to hedge up to 65% of total estimated natural gas and liquids production over the first three years and 50% over the fourth year.

Our current hedging positions are summarized as follows:

Period	**Average Production Hedged**	**Forecast Production Hedged** (net of royalties)	**Average Price AECO ($Cdn.)**
Q1 2015 to Q4 2015	82.9 mmcf/d	57%	$3.86/mcf
Q1 2016 to Q4 2016	84.1 mmcf/d	46%	$3.69/mcf
Q1 2017	80.6 mmcf/d	42%	$3.65/mcf

A summary of realized and unrealized hedging gains and losses for the three months and year ended December 31, 2014 and 2013 are as follows:

($000)	Three months ended December 31 2014	Three months ended December 31 2013	% change	Year ended December 31 2014	Year ended December 31 2013	% change
Realized gains (losses) on derivatives	$ (777)	$ 1,758	(144)%	$ (12,550)	$ 2,853	(540)%
Unrealized gains (losses) on derivatives	55,243	(11,472)	(582)%	47,786	(6,043)	(891)%
Total gains (losses) on derivatives	**$ 54,466**	**$ (9,714)**	**(661)%**	**$ 35,236**	**$ (3,190)**	**(1,205)%**

For the three months and year ended December 31, 2014, we realized derivative losses as a result of higher natural gas prices as compared to our average hedge prices. For the year ended December 31, 2014, $47.8 million was recognized in income as an unrealized derivative gain (December 31, 2013 – $6.0 million unrealized derivative loss), being the increase in fair value to a net derivative asset of $46.6 million at December 31, 2014 as compared to a net derivative liability at December 31, 2013. The fair value of the net derivative asset is the estimated value to settle the contracts as at a point in time. As such, unrealized derivative gains and losses are not cash and the actual gains or losses realized on eventual cash settlement can vary materially due to subsequent fluctuations in commodity prices as compared to the valuation assumptions. These derivative contracts will settle from January 1, 2015 to March 31, 2017 corresponding to when the Corporation will recognize sales from production.

Royalties

	Three months ended December 31			Year ended December 31		
	2014	2013	% change	2014	2013	% change
Royalties ($000)	$ 2,209	$ 1,523	45%	$ 10,076	$ 7,534	34%
per mcfe	$ 0.18	$ 0.15	20%	$ 0.21	$ 0.18	17%
Royalty Rate (percentage of natural gas and liquids sales)	4.7%	4.7%	-%	4.7%	5.4%	(0.7)%

Advantage pays royalties to the owners of mineral rights from which we have leases. The Corporation currently has mineral leases with provincial governments, individuals and other companies. Our average corporate royalty rates are impacted by well depths, well production rates, commodity prices, and gas cost allowance. The expected royalty rate for the life of a Glacier Upper and Lower Montney horizontal well is approximately 5% before gas cost allowance due to industry provincial incentive programs. Total royalties paid during the three months and year ended December 31, 2014 are higher than 2013 due to stronger natural gas prices and increased natural gas production while the overall royalty rate has decreased slightly.

Operating Expense

	Three months ended December 31			Year ended December 31		
	2014	2013	% change	2014	2013	% change
Operating expense ($000)	$ 4,184	$ 2,772	51%	$ 15,412	$ 20,515	(25)%
per mcfe	$ 0.34	$ 0.28	21%	$ 0.32	$ 0.48	(33)%

For the year ended December 31, 2014, operating expense was $0.32/mcfe, a decrease of 33% as compared to 2013. Operating costs have decreased with the disposition of higher cost non-core assets and due to the increased production from our 100% owned Glacier gas plant. Operating expense per mcfe for the fourth quarter of 2014 was $0.34/mcfe due to higher third party water disposal and trucking costs resulting from the flowback of additional water from well completions.

General and Administrative Expense

	Three months ended December 31			Year ended December 31		
	2014	2013	% change	2014	2013	% change
General and administrative expense						
Cash expense ($000)	$ 1,371	$ 3,932	(65)%	$ 7,426	$ 19,246	(61)%
per mcfe	$ 0.11	$ 0.39	(72)%	$ 0.15	$ 0.45	(67)%
Share based compensation ($000)	$ 577	$ 656	(12)%	$ 2,153	$ 5,180	(58)%
per mcfe	$ 0.05	$ 0.07	(29)%	$ 0.04	$ 0.12	(67)%
Total general and administrative expense ($000)	$ 1,948	$ 4,588	(58)%	$ 9,579	$ 24,426	(61)%
per mcfe	$ 0.16	$ 0.46	(65)%	$ 0.19	$ 0.57	(67)%
Employees at December 31				27	80	(66)%

Cash general and administrative (“G&A”) expense has decreased as significant cost efficiencies were realized with the non-core asset dispositions and termination of the Technical Services Agreement with Longview on February 1, 2014 whereby Advantage had previously provided the necessary personnel and technical services to manage Longview's business. Cash G&A in 2013 included one-time costs including retention and staff rationalization associated with the asset dispositions and costs incurred during Advantage’s strategic alternatives review process that commenced in early 2013 and was concluded on February 4, 2014.

Share based compensation represents non-cash G&A expense associated with Advantage's stock option plan and restricted and performance award plan that are designed to provide for long term compensation to service providers. Share based compensation for the three months and year ended December 31, 2014 has decreased as a result of staff rationalization. As at December 31, 2014, a total of 5.1 million stock options and 0.4 million performance awards are unexercised which represents only 3.3% of the 10% of Advantage's total outstanding common shares which are eligible to be granted to service providers.

Depreciation Expense

	Three months ended December 31			Year ended December 31		
	2014	2013	% change	2014	2013	% change
Depreciation expense ($000)	$ 21,329	$ 17,958	19%	$ 85,460	$ 72,140	18%
per mcfe	$ 1.73	$ 1.80	(4)%	$ 1.78	$ 1.69	5%

Depreciation of natural gas and liquids properties is provided on the units-of–production method based on total proved and probable reserves, including future development costs, on a component basis. Depreciation expense was higher during 2014 due to the continued increase in production at Glacier. The rate of depreciation expense recognized at Glacier decreased in 2014 as total costs, including future development costs, as a proportion of total proved and probable reserves declined due to the continued efficiency of production additions. Depreciation expense per mcfe was modestly lower during the year ended December 31, 2013 as Advantage ceased depreciation of assets held for sale for the period of January 1, 2013 to April 30, 2013.

Finance Expense

	Three months ended December 31			Year ended December 31		
	2014	2013	% change	2014	2013	% change
Finance expense						
Cash expense ($000)	$ 2,502	$ 3,174	(21)%	$ 10,267	$ 12,097	(15)%
per mcfe	$ 0.20	$ 0.32	(38)%	$ 0.21	$ 0.28	(25)%
Accretion expense ($000)	$ 1,124	$ 1,123	-%	$ 4,525	$ 6,128	(26)%
per mcfe	$ 0.09	$ 0.11	(18)%	$ 0.09	$ 0.14	(36)%
Total finance expense ($000)	$ 3,626	$ 4,297	(16)%	$ 14,792	$ 18,225	(19)%
per mcfe	$ 0.29	$ 0.43	(33)%	$ 0.30	$ 0.42	(29)%
Bank indebtedness ($000)				$ 109,970	$ 153,697	(28)%

Cash finance expense from interest on bank indebtedness and the convertible debenture have decreased compared to 2013, due to the lower average bank indebtedness. Our bank indebtedness outstanding as at December 31, 2014 was $110.0 million, a decrease of $43.7 million from December 31, 2013. The Corporation's interest rates on bank indebtedness have decreased due to the lower debt to cash flow ratios as calculated pursuant to our Credit Facilities and are primarily based on short term bankers' acceptance rates plus a stamping fee.

Accretion expense represents non-cash charges that increase the carrying value of the convertible debenture and decommissioning liability as a result of the passage of time. The convertible debenture outstanding at December 31, 2014 matured on January 30, 2015, and was settled from the Credit Facilities. Accretion expense for the year ended December 31, 2014 is lower than 2013 as the decommissioning liability decreased in April 2013 with the closing of non-core asset sales.

Other Income (Expense)

($000)	Three months ended December 31 2014	Three months ended December 31 2013	% change	Year ended December 31 2014	Year ended December 31 2013	% change
Interest income - Questfire Debenture	$ -	$ 492	(100)%	$ 455	$ 1,312	(65)%
Accretion income - Questfire Debenture	-	569	(100)%	557	1,516	(63)%
Loss on disposition - Questfire Debenture	-	-	-%	(13,833)	-	100%
Unrealized gain (loss) - Questfire Class B Shares	-	(750)	(100)%	150	(900)	(117)%
Gain (loss) on sale of assets	-	505	(100)%	(1,489)	(6,354)	(77)%
Miscellaneous income	3,039	427	612%	3,633	447	713%
	$ 3,039	$ 1,243	144%	$ (10,527)	$ (3,979)	165%

Advantage recognized interest and accretion income earned on the Questfire Debenture from April 2013 up to the first quarter of 2014, the time during which we owned the Debenture. During the first quarter of 2014, Advantage accepted a proposal from Questfire to redeem the Questfire Debenture for an aggregate purchase price of $13.6 million and Advantage recognized a loss of $13.8 million representing the difference from the carrying value. Advantage also accepted a Questfire offer to purchase by way of issuer bid, all of the Class B Shares at a price of $2.60 per share. Advantage received $3.9 million in the second quarter of 2014 for the Class B Shares and recognized a net gain of $0.2 million. Advantage recognized a loss of $1.5 million in the second quarter related to the finalization of the gain and loss calculations attributable to non-core asset dispositions that closed in 2013. During the fourth quarter of 2014, Advantage settled a dispute with a former joint venture partner related to properties which Advantage had disposed. The effect of this settlement resulted in net funds received by Advantage of $3.0 million.

Taxes

Deferred income taxes arise from differences between the accounting and tax bases of our assets and liabilities. For the year ended December 31, 2014, the Corporation recognized a deferred income tax expense of $30.4 million as a result of the $105.0 million income before taxes from continuing operations. As at December 31, 2014, the Corporation had a deferred income tax liability balance of $33.4 million.

Estimated tax pools at December 31, 2014, are as follows:

	($ millions)
Canadian Development Expenses	$ 219
Canadian Exploration Expenses	66
Canadian Oil and Gas Property Expenses	3
Non-capital losses	734
Capital losses	158
Undepreciated Capital Cost	169
Other	10
	$ 1,359

Net Income (Loss) and Comprehensive Income (Loss) from Continuing Operations

	Three months ended December 31			Year ended December 31		
	2014	**2013**	**% change**	**2014**	**2013**	**% change**
Net income (loss) and comprehensive income (loss) from continuing operations ($000)	$ 53,682	$ (6,273)	(956)%	$ 74,597	$ (8,297)	(999)%
per share - basic and diluted	$ 0.32	$ (0.04)	(900)%	$ 0.44	$ (0.05)	(980)%

Advantage's net income from continuing operations for 2014 has increased significantly as compared to 2013 primarily due to higher funds from operations attributable to increased Glacier production, stronger natural gas prices and a lower cost structure. All reporting periods were affected by derivative gains and losses from our ongoing commodity price risk management activities. For the year ended December 31, 2014, Advantage has recognized total gains on derivatives of $35.2 million as compared to a $3.2 million total loss on derivatives for the same period of 2013. One-time non-cash losses of approximately $15.2 million were recognized on disposition of Questfire investments and non-core properties in the first half of 2014.

Contractual Obligations and Commitments

The Corporation has contractual obligations in the normal course of operations including purchases of assets and services, operating agreements, transportation commitments, sales contracts, bank indebtedness and convertible debentures. These obligations are of a recurring and consistent nature and impact cash flow in an ongoing manner. The following table is a summary of the Corporation's remaining contractual obligations and commitments. Advantage has no guarantees or off-balance sheet arrangements other than as disclosed.

	Payments due by period					
($ millions)	**Total**	**2015**	**2016 & 2017**	**2018 & 2019**	**2020**	**After 2020**
Building leases	$ 5.2	$ 1.1	$ 2.3	$ 1.8	$ -	$ -
Pipeline/transportation	119.5	17.1	37.7	31.3	9.6	23.8
Bank indebtedness [1] - principal	110.3	-	110.3	-	-	-
- interest	10.1	6.8	3.3	-	-	-
Convertible debenture [2] - principal	86.3	86.3	-	-	-	-
- interest	2.1	2.1	-	-	-	-
Total contractual obligations	**$ 333.5**	**$ 113.4**	**$ 153.6**	**$ 33.1**	**$ 9.6**	**$ 23.8**

(1) As at December 31, 2014, the Corporation's bank indebtedness was governed by a credit facility agreement with a syndicate of financial institutions. Under the terms of the agreement, the facility is reviewed annually, with the next review scheduled in June 2015. The facility is revolving and 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. Management fully expects that the facility will be extended at each annual review.

(2) As at December 31, 2014, Advantage had an $86.2 million convertible debenture outstanding that was convertible to common shares based on an established conversion price. The convertible debenture matured on January 30, 2015, and was settled from the Credit Facilities.

Liquidity and Capital Resources

The following table is a summary of the Corporation's capitalization structure:

($000, except as otherwise indicated)		**December 31, 2014**
Bank indebtedness (non-current)	$	109,970
Working capital deficit (1)		57,264
Net debt		167,234
Convertible debenture maturity value (current)		86,250
Total debt	**$**	**253,484**
Shares outstanding		170,067,650
Shares closing market price ($/share)	$	5.56
Market capitalization (2)	**$**	**945,576**
Total capitalization	**$**	**1,199,060**
Total debt to funds from operations (3)		**1.5**

(1) Working capital deficit is a non-GAAP measure that includes trade and other receivables, prepaid expenses and deposits, and trade and other accrued liabilities.
(2) Market capitalization is a non-GAAP measure calculated by multiplying shares outstanding by the closing market share price on the applicable date.
(3) Total debt is a non-GAAP measure that includes bank indebtedness, working capital deficit and the convertible debenture maturity value. Total debt to funds from operations is calculated by dividing total debt by funds from operations.

Advantage monitors its capital structure and makes adjustments according to market conditions in an effort to meet its objectives given the current outlook of the business and industry in general. The capital structure of the Corporation is composed of working capital deficit, bank indebtedness, convertible debentures and share capital. Advantage may manage its capital structure by issuing new common shares, repurchasing outstanding common shares, obtaining additional financing either through bank indebtedness or convertible debenture issuances, refinancing current debt, issuing other financial or equity-based instruments, declaring a dividend, adjusting capital spending, or disposing of assets. The capital structure is reviewed by Management and the Board of Directors on an ongoing basis.

Management of the Corporation's capital structure is facilitated through its financial and operational forecasting processes. Selected forecast information is frequently provided to the Board of Directors. This continual financial assessment process further enables the Corporation to mitigate risks. The Corporation continues to satisfy all liabilities and commitments as they come due and has $290 million available on our $400 million credit facility at December 31, 2014. For the year ended December 31, 2015, we will be funding our capital expenditures from funds from operations and our Credit Facilities, and have estimated that our total debt to trailing funds from operations ratio will be approximately 2.1 based on a $2.50/GJ natural gas price. We will continue to be very cognizant of maintaining financial flexibility in the current environment.

Shareholders' Equity and Convertible Debentures

As at December 31, 2014, Advantage had 170.1 million common shares outstanding. During 2014, Advantage issued 1.7 million common shares to service providers in exchange for the exercise of 7.4 million stock options including 5.0 million stock options that vested during 2013 but could not be exercised due to trading blackout restrictions imposed by the previous strategic review process that was terminated on February 4, 2014. Additionally, 4.3 million stock options were forfeited/cancelled in 2014 due to staff rationalization associated with the asset dispositions. For the year ended December 31, 2014, 3.8 million stock options and 0.4 million performance awards were granted to service providers with a vesting term of three years. As at December 31, 2014, a total of 5.1 million stock options and 0.4 million performance awards are unexercised which represents only 3.3% of the 10% of Advantage's total outstanding common shares which are eligible to be granted to service providers. As at March 25, 2015, Advantage had 170.3 million common shares outstanding.

The Corporation had $86.2 million of 5.00% convertible debentures outstanding at December 31, 2014 that were convertible to 10.0 million common shares based on the applicable conversion price (December 31, 2013 - $86.2 million outstanding and convertible to 10.0 million common shares). The convertible debentures matured on January 30, 2015 and was settled from the Credit Facilities.

Bank Indebtedness, Credit Facilities and Other Obligations

At December 31, 2014, Advantage had bank indebtedness outstanding of $110.0 million. Bank indebtedness has decreased $43.7 million since December 31, 2013 due to net proceeds received from the disposition of investments in Longview and Questfire, and strong funds from operations. Advantage's credit facilities borrowing base is $400 million and is collateralized by a $1 billion floating charge demand debenture covering all assets of the Corporation (the "Credit Facilities"). The borrowing base for the Credit Facilities is determined by the banking syndicate through a thorough evaluation of our reserve estimates based upon their own commodity price expectations. Revisions or changes in the reserve estimates and commodity prices can have either a positive or a negative impact on the borrowing base. The next annual review is scheduled to occur in June 2015. There can be no assurance that the Credit Facilities will be renewed at the current borrowing base level at that time.

Advantage had a working capital deficiency of $57.3 million as at December 31, 2014, an increase from the prior quarter due to the relatively high level of capital expenditure activity underway at December 31, 2014. Our working capital includes items expected for normal operations such as trade receivables, prepaids, deposits, and trade payables and accruals. Working capital varies primarily due to the timing of such items, the current level of business activity including our capital expenditure program, commodity price volatility, and seasonal fluctuations. Our working capital is normally in a deficit position due to our continuing capital development activities. We do not anticipate any problems in satisfying the working capital deficit and meeting future obligations as they become due as they can be satisfied with funds from operations and our available Credit Facilities.

Capital Expenditures

	Three months ended December 31		Year ended December 31	
($000)	**2014**	**2013**	**2014**	**2013**
Drilling, completions and workovers	$ 66,144	$ 65,182	$ 195,802	$ 135,507
Well equipping and facilities	20,292	4,257	37,662	12,977
Land and seismic	-	31	-	55
Expenditures on property, plant and equipment	86,436	69,470	233,464	148,539
Expenditures on exploration and evaluation assets	650	42	3,237	6,831
Proceeds from property dispositions (1)	-	(505)	-	(52,903)
Net capital expenditures (2)	**$ 87,086**	**$ 69,007**	**$ 236,701**	**$ 102,467**

(1) Proceeds from property dispositons represents the net cash proceeds and excludes all other forms of consideration.
(2) Net capital expenditures excludes changes in non-cash working capital and change in decommissioning liability.

Advantage invested $233.5 million on property, plant and equipment at Glacier for the year ended December 31, 2014. We ramped up our capital development program at Glacier in the third quarter of 2013 resulting in additional production during the first quarter of 2014, and we reached our target of 135 mmcfe/d in March 2014. We have since maintained production between 130 mmcfe/d and 135 mmcfe/d. Enhanced well performance and lower production declines from wells drilled have exceeded expectations. The last well from our most recent capital program is now not anticipated to be required to be placed on production until July 2015.

Our most recent capital program consisted of drilling 33 new Montney wells, and was designed to grow production at Glacier to 183 mmcfe/d including 900 bbls/d of natural gas liquids by July 2015. Drilling commenced in March 2014 with one rig drilling through spring breakup and then increasing to three drilling rigs in July 2014. All 33 Montney wells have now been drilled and rig released and 22 of the 33 wells have been completed and will be available to increase production to our target volume of 183 mmcfe/d in July 2015 and hold production at that level until the first quarter of 2016. The remaining 11 wells will be completed and brought on production as required in 2016. First quarter 2015 activity, which consisted of drilling 10 wells and completing 6 wells is included as part of the Corporation's 2015 capital budget.

Advantage's 100% owned Glacier gas plant is currently being expanded with commissioning expected in July 2015. Processing capacity is being expanded to 250 mmcf/d including 70 mmcf/d of spare capacity to meet future production growth in 2016 and 2017. Additionally, the plant will be capable of processing varying amounts of dry and liquids rich gas production with the installation of natural gas liquids extraction and condensate stabilization equipment.

In 2014 Advantage acquired 9 additional sections of land with Lower Doig/Montney rights in the greater Glacier area. Advantage now holds a total of 129 sections (82,560 acres) of either Lower Doig or Montney rights.

Firm service transportation commitments have been secured to coincide with Advantage's 2016 production target of 205 mmcfe/d.

Sources and Uses of Funds

The following table summarizes the various funding requirements during the years ended December 31, 2014 and 2013 and the sources of funding to meet those requirements:

	Year ended December 31	
($000)	**2014**	**2013**
Sources of funds		
Funds from operations	$ 164,010	$ 85,310
Disposition of Longview investment	90,153	-
Disposition of Questfire investments	17,500	-
Change in non-cash working capital and other	7,830	16,390
Dividends received from Longview	1,692	12,691
Property dispositions	-	52,903
	$ 281,185	**$ 167,294**
Uses of funds		
Expenditures on property, plant and equipment	$ 233,464	$ 148,539
Decrease in bank indebtedness	44,038	7,260
Expenditures on exploration and evaluation assets	3,237	6,831
Expenditures on decommissioning liability	446	4,664
	$ 281,185	**$ 167,294**

The increased funds from operations combined with proceeds from the disposition of investments in Longview and Questfire were used to fund capital expenditures and repay a significant portion of bank indebtedness. Bank indebtedness has been significantly reduced and we monitor the debt level to ensure an optimal mix of financing and cost of capital that will provide a maximum return to our shareholders.

FINANCIAL AND OPERATING REVIEW – DISCONTINUED OPERATIONS

The following financial and operating highlights for Longview to February 28, 2014 have been presented to provide additional information with respect to the Longview segment prior to disposition.

	Year ended December 31	
	2014 (1)	**2013**
Production (boe/d)	5,622	5,953
Funds from operations ($000)	$ 9,693	$ 63,195
Net capital expenditures ($000)	$ 19,092	$ 38,696
Net income (loss) and comprehensive income (loss) from discontinued operations ($000)	$ (58,894)	$ 4,915
per share - basic and diluted	$ (0.35)	$ 0.03

(1) Represents the financial and operating results for the Longview segment for the 59 days from January 1, 2014 to February 28, 2014.

Financial and operating results from Longview for 2014 are significantly impacted, particularly the reduction in funds from operations, as it only represents 59 days due to the disposition of Longview on February 28, 2014 as opposed to the 365 days for the year ended December 31, 2013. Advantage has recognized a consolidated net loss of $58.9 million from the Longview segment during the first quarter of 2014 due to a $58.8 million loss on disposition as the net proceeds received by Advantage were less than the carrying value of the net assets.

Annual Financial Information

The following is a summary of selected financial information of the Corporation for the years indicated.

	Year ended Dec. 31, 2014	Year ended Dec. 31, 2013	Year ended Dec. 31, 2012
Continuing Operations - Advantage			
Total sales (before royalties) ($000)	$ 215,653	$ 140,090	$ 129,131
Net income (loss) ($000)	$ 74,597	$ (8,297)	$ (85,766)
per share - basic and diluted	$ 0.44	$ (0.05)	$ (0.51)
Total assets ($000)	$ 1,454,767	$ 1,309,543	$ 1,424,010
Long term financial liabilities ($000) (1)	$ 110,482	$ 236,151	$ 239,724
Discontinued Operations - Longview			
Total sales (before royalties) ($000)	$ 24,715	$ 149,652	$ 139,774
Net income (loss) ($000)	$ (58,894)	$ 4,915	$ (3,359)
per share - basic and diluted	$ (0.35)	$ 0.03	$ (0.02)
Total assets ($000)	$ -	$ 455,701	$ 489,786
Long term financial liabilities ($000) (1)	$ -	$ 117,642	$ 111,895

(1) Long term financial liabilities exclude derivative liability, decommissioning liability and deferred income tax liability.

Quarterly Performance

($000, except as otherwise indicated)	2014 Q4	2014 Q3	2014 Q2	2014 Q1	2013 Q4	2013 Q3	2013 Q2	2013 Q1
Continuing Operations - Advantage								
Daily production								
Natural gas (mcf/d)	133,433	131,553	134,912	122,481	108,260	111,518	116,469	119,692
Liquids (bbls/d)	113	161	200	164	79	105	554	1,308
Total (mcfe/d)	134,111	132,519	136,112	123,465	108,734	112,148	119,793	127,540
Average prices								
Natural gas ($/mcf)								
Excluding hedging	$ 3.78	$ 4.03	$ 4.71	$ 5.21	$ 3.21	$ 2.46	$ 3.47	$ 2.98
Including hedging	$ 3.72	$ 3.80	$ 4.27	$ 4.89	$ 3.39	$ 2.63	$ 3.35	$ 3.04
AECO daily	$ 3.61	$ 4.02	$ 4.69	$ 5.59	$ 3.52	$ 2.45	$ 3.55	$ 3.20
Liquids ($/bbl)								
Including hedging	$ 71.35	$ 83.14	$ 102.41	$ 94.10	$ 77.01	$ 95.13	$ 73.22	$ 75.58
Edmonton Light ($/bbl)	$ 75.54	$ 97.07	$ 105.65	$ 99.99	$ 86.88	$ 104.96	$ 92.99	$ 88.78
Total sales including realized hedging	$ 46,409	$ 47,190	$ 54,265	$ 55,239	$ 34,304	$ 27,857	$ 39,184	$ 41,598
Net income (loss)	$ 53,682	$ 14,201	$ 24,330	$ (17,616)	$ (6,273)	$ (3,187)	$ 6,543	$ (5,380)
per share - basic and diluted	$ 0.32	$ 0.08	$ 0.14	$ (0.10)	$ (0.04)	$ (0.02)	$ 0.04	$ (0.03)
Funds from operations	$ 39,182	$ 36,818	$ 42,561	$ 45,449	$ 23,822	$ 16,516	$ 23,488	$ 21,484
Discontinued Operations - Longview								
Total sales including realized hedging	$ -	$ -	$ -	$ 23,237	$ 33,721	$ 38,234	$ 37,179	$ 33,729
Net income (loss)	$ -	$ -	$ -	$ (58,894)	$ 870	$ 1,845	$ 1,799	$ 401
per share - basic and diluted [1]	$ -	$ -	$ -	$ (0.35)	$ 0.01	$ 0.01	$ 0.01	$ -
Funds from operations	$ -	$ -	$ -	$ 9,693	$ 13,740	$ 17,959	$ 16,683	$ 14,813

[1] Per share amounts based on weighted average basic and diluted shares outstanding of Advantage Oil & Gas Ltd.

The table above highlights the Corporation's performance for the fourth quarter of 2014 and also for the preceding seven quarters for both continuing and discontinued operations. Production during the first quarter of 2013 reflects the last full interim period in which Advantage owned non-core assets. As of April 30, 2013, the sale of these non-core assets was completed and Advantage was transformed into a pure play Montney producer with a single focus on development of our Glacier, Alberta area. Accordingly, production was lower from the second to fourth quarters of 2013. We ramped up our capital development program at Glacier in the third quarter of 2013 resulting in additional production during the first quarter of 2014, and we reached our target of 135 mmcfe/d in March 2014. Currently, Advantage has an inventory of 33 wells drilled from our most recent capital program. We have in excess of 185 mmcf/d of first month productivity from 22 completed wells and a number of older wells which are currently shut-in due to plant capacity constraints. These standing wells will be utilized to increase production to 183 mmcfe/d in July 2015 and are capable of sustaining production to early 2016. The remaining 11 wells drilled from our 2014 program will be completed and brought on production as required in 2016.

During the third quarter of 2013, sales and funds from operations decreased due to significant reductions in AECO prices that impacted the entire Alberta natural gas industry. Sales and funds from operations increased dramatically in 2014 primarily attributable to improved natural gas prices and production growth. In 2013, Advantage has reported net losses primarily driven by weak natural gas prices. In the first quarter of 2014, Advantage recognized a $13.8 million loss on redemption of the Questfire Debenture and a $58.8 million loss on disposition of the Longview operating segment as the net proceeds received by Advantage were less than the carrying value of the net assets. As a pure Montney producer Advantage now has a much simpler capitalization structure and a strong balance sheet to continue its multi-year development plan. Advantage's production growth at Glacier has resulted in increased total sales including realized hedging, net income and funds from operations from the second quarter of 2014 to the fourth quarter of 2014.

Critical Accounting Estimates

The preparation of financial statements in accordance with IFRS requires Management to make certain judgments and estimates. Changes in these judgments and estimates could have a material impact on the Corporation’s financial results and financial condition.

Management relies on the estimate of reserves as prepared by the Corporation’s independent qualified reserves evaluator. The process of estimating reserves is critical to several accounting estimates. The process of estimating reserves is complex and 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 and production activities becomes available and as economic conditions impact natural gas and liquids prices, operating expense, royalty burden changes, and future development costs. Reserve estimates impact net income and comprehensive income through depreciation and impairment of natural gas and liquids properties. The reserve estimates are also used to assess the borrowing base for the Corporation’s Credit Facilities. Revision or changes in the reserve estimates can have either a positive or a negative impact on asset values, net income, comprehensive income and the borrowing base of the Corporation.

Management’s process of determining the provision for deferred income taxes, the provision for decommissioning liability costs and related accretion expense and the fair values initially assigned to the convertible debentures liability and equity components are based on estimates. These estimates are significant and can include proved and probable reserves, future production rates, future commodity prices, future costs, future interest rates, future tax rates and other relevant assumptions. Revisions or changes in any of these estimates can have either a positive or a negative impact on asset and liability values, net income and comprehensive income.

In accordance with IFRS, derivative assets and liabilities are recorded at their fair values at the reporting date, with gains and losses recognized directly into comprehensive income in the same period. The fair value of derivatives outstanding is an estimate based on pricing models, estimates, assumptions and market data available at that time. As such, the recognized amounts are non-cash items and the actual gains or losses realized on eventual cash settlement can vary materially due to subsequent fluctuations in commodity prices as compared to the valuation assumptions.

Changes in Accounting Policies

There have been no changes in accounting policies during the year ended December 31, 2014.

Accounting Pronouncements not yet Adopted

Standards issued but not yet effective up to the date of issuance of the Corporation’s financial statements are evaluated as to whether we expect changes to our financial reporting when they become effective. As at March 25, 2015, we do not expect any of the standards issued but not effective to result in changes to our current financial reporting when they become effective.

Evaluation of Disclosure Controls and Procedures

Advantage’s Chief Executive Officer and Chief Financial Officer have designed disclosure controls and procedures (“DC&P”), or caused it to be designed under their supervision, to provide reasonable assurance that material information relating to the Corporation is made known to them by others, particularly during the period in which the annual filings are being prepared, and information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation.

Management of Advantage, including our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the Corporation’s DC&P as at December 31, 2014. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that the DC&P are effective as of the end of the year, in all material respects.

Evaluation of Internal Controls over Financial Reporting

Advantage's Chief Executive Officer and Chief Financial Officer are responsible for establishing and maintaining internal control over financial reporting ("ICFR"). They have as at the financial year end December 31, 2014, designed ICFR, or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The control framework Advantage's officers used to design the Corporation's ICFR is the Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations.

Management of Advantage, including our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the Corporation's ICFR as at December 31, 2014. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that the ICFR are effective as of the end of the year, in all material respects.

Advantage's Chief Executive Officer and Chief Financial Officer are required to disclose any change in the ICFR that occurred during our most recent interim period that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR. No material changes in the ICFR were identified during the interim period ended December 31, 2014 that have materially affected, or are reasonably likely to materially affect, our ICFR.

It should be noted that while the Chief Executive Officer and Chief Financial Officer believe that the Corporation's design of DC&P and ICFR provide a reasonable level of assurance that they are effective, they do not expect that the control system will prevent all errors and fraud. A control system, no matter how well conceived or operated, does not provide absolute, but rather is designed to provide reasonable assurance that the objective of the control system is met. The Corporation's ICFR may not prevent or detect all misstatements because of inherent limitations. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or deterioration in the degree of compliance with the Corporation's policies and procedures.

Corporate Governance

The Corporation's corporate governance practices can be found in the Management Information Circular.

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

Additional Information

Additional information relating to Advantage can be found on SEDAR at www.sedar.com and the Corporation's website at www.advantageog.com. Such other information includes the annual information form, the management information circular, press releases, material change reports, material contracts and agreements, and other financial reports. The annual information form will be of particular interest for current and potential shareholders as it discusses a variety of subject matter including the nature of the business, description of our operations, general and recent business developments, risk factors, reserves data and other oil and gas information.

March 25, 2015