UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

OMB APPROVAL
OMB Number: 3235-0381 Expires: July 31, 2014 Estimated average burden hours per response…..427

FORM 40-F

☐ 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, 2011 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 700, 400 – 3 Avenue SW, Calgary, Alberta T2P 4H2 (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: 166,304,040

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, 2011 (filed herein as Exhibit 99.1)
2.	Consolidated Financial Statements of the Registrant for the fiscal year ended December 31, 2011, 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, 2011 (filed herein as Exhibit 99.3).
4.	Consent of PricewaterhouseCoopers LLP to the inclusion of the Auditors' Report dated March 23, 2012 on the Registrant's Audited Consolidated Financial Statements for the fiscal year ended December 31, 2011.
5.	Consent of Sproule Associated 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, 2011.
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 Annual Information Form for the fiscal year ended December 31, 2011, see Exhibit 99.1 included herein.

B. Audited Annual Financial Statements

For consolidated audited financial statements, including the report of independent chartered accountants with respect thereto, see the Consolidated Financial Statements of the Registrant for the fiscal year ended December 31, 2011, included as Exhibit 99.2 herein.

C. Consolidated Management's Discussion and Analysis

For management's discussion and analysis, see Management's Discussion and Analysis of the Registrant for the fiscal year ended December 31, 2011, included as Exhibit 99.3 herein.

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, 2011, 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 "Controls and Procedures" and "Evaluation of Disclosure Controls and Procedures" sections of Management's Discussion and Analysis of the Registrant for the fiscal year ended December 31, 2011, 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, 2011, filed as part of this Annual Report on Form 40-F.

D. ATTESTATION REPORT OF THE REGISTERED PUBLIC ACCOUNTING FIRM. The required disclosure is included in the "Report of Independent Registered Public Accounting Firm" that accompanies the Registrant's Consolidated Financial Statements for the fiscal year ended December 31, 2011, 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, 2011, 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 "Controls and Procedures" section of Management's Discussion and Analysis of the Registrant for the fiscal year ended December 31, 2011, 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 Chief Executive Officer, President and Chief Financial Officer, Senior Vice President, the Vice President, Finance, Vice President, Geosciences and Land, Vice President Exploitations, 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: Carol Pennycook, Paul Haggis, Ronald McIntosh 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, 2011 and December 31, 2010, totaled $526,000 and $896,350, 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, 2011	Year ended December 31, 2010
Audit Fees	$ 486,000	$ 645,000
Audit Related Fees	$ 40,000	$ 251,350
Tax Fees	$ 0	$ 0
All Other Fees	$ 0	$ 0
TOTAL	$ 526,000	$ 896,350

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. These services include French translation in connection with prospectus filing.

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).

All Other Fees

None.

PREAPPROVAL POLICIES AND PROCEDURES

In 2011, 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	$ 7.4	$ 3.4	$ 4.0	$	$
Pipeline/Transportation	$ 36.6	$ 12.1	$ 22.3	$ 2.2	$
Bank Indebtedness	$ 252.2	$ 12.4	$ 239.8	$	$
Convertible Debenture(1)	$ 101.3	$ 4.3	$ 8.6	$ 88.4	$
Total Contractual Obligations	$ 397.5	$ 32.2	$ 274.7	$ 90.6	$

(1) The Corporation's bank indebtedness does not have specific maturity dates. It is governed by credit facility agreements with a syndicate of financial institutions. Under the terms of the agreements, the facilities are reviewed annually, with the next reviews scheduled in April and June 2012. The facilities are revolving, and 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.

(2) As at December 31, 2011, Advantage had $86.2 million convertible debentures outstanding. The convertible debentures are convertible to common shares based on an established conversion price. All remaining obligations related to convertible debentures can be settled through the payment of cash or issuance of common shares at Advantage's option.

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. Steven Sharpe 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, Canterra Tower, Suite 700, 400 - 3 Avenue SW, Calgary, Alberta T2P 4H2, 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, Canterra Tower, Suite 700, 400 - 3 Avenue SW, Calgary, Alberta T2P 4H2.

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 23, 2012 on the Registrant's Audited Consolidated Financial Statements for the fiscal year ended December 31, 2011.
23.2	Consent of Sproule Associated 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, 2011.
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, 2011.
99.2	Consolidated Financial Statements of the Registrant for the fiscal year ended December 31, 2011, 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, 2011.

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 23, 2012

ADVANTAGE OIL & GAS LTD.

By: /s/ Kelly Drader
Name: Kelly Drader
Title: Chief Financial Officer

Exhibit 23.1

Consent of Independent Auditor's

We hereby consent to the inclusion in this Annual Report on Form 40-F for the year ended December 31, 2011 of Advantage Oil & Gas Ltd. of our report dated March 23, 2012, relating to the consolidated financial statements as at December 31, 2011, December 31, 2010 and January 1, 2010 and for each of the years in the two year period ended December 31, 2011 and 2010, and the effectiveness of internal control over financial reporting of Advantage Oil & Gas Ltd. as at December 31, 2011.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta

March 26, 2012

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 23, 2012

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, 2011)", dated February 28, 2012 (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, 2011.

Sincerely,

SPROULE ASSOCIATES LIMITED

By: /s/ Cameron P. Six
Name: Cameron P. Six, P. Eng
Title: Manager, Engineering

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 principals;

   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 23, 2012

/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, Kelly I. Drader, 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 principals;

   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 23, 2012

/s/ Kelly I. Drader
Kelly I. Drader
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, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Andy J. Mah, 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 23, 2012

/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, 2011 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Kelly I. Drader, President 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 23, 2012

/s/ Kelly I. Drader
Kelly I. Drader
Chief Financial Officer

ANNUAL INFORMATION FORM

YEAR ENDED DECEMBER 31, 2011

March 23, 2012

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GLOSSARY OF TERMS

Selected Defined Terms

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

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

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

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

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

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

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

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

"**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 Non-Controlling Interest**" means the approximately 37% interest of third party minority public shareholders in the 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;

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

"**Trust Conversion**" means the plan of arrangement pursuant to Section 193 of the ABCA, which closed on July 9, 2009 and pursuant to which, among other things, the Trust was dissolved and the Corporation became the resulting entity;

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

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

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

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

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

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

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

Selected Defined Oil and Gas Terms

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

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

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

"**Current Production**" means average daily gross production for the three month period ended December 31, 2011;

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

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

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

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

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, pumping equipment and wellhead assembly;

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

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

(d) provide improved recovery systems;

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

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

"**Total Current Production**" means aggregate average daily gross production from the Properties for the three month period ended December 31, 2011; and

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

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

ABBREVIATIONS

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

Other

BOE or boe	means barrel of oil equivalent, using the conversion factor of 6 Mcf of natural gas being equivalent to one bbl of oil.
WTI	means West Texas Intermediate.
°API	means the measure of the density or gravity of liquid petroleum products derived from a specific gravity.
psi	means pounds per square inch.

The term "boe" or barrels of oil equivalent may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent (6 Mcf: 1 bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. 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	28.174
cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	bbls	6.293
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
gigajoules	MMbtu	0.950

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;
- focus of capital budget;
- timing of development of undeveloped reserves;
- future abandonment and reclamation costs;
- tax horizons;
- terms of Longview's material contracts discussed under "*Material Contracts*";
- 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 resources and reserves described can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward looking statements contained in this annual information form are expressly qualified by this cautionary statement.

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; current or, where applicable, proposed assumed industry conditions, laws and regulations will continue in effect or as anticipated as described herein; and 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.

Moreover, the current global economic conditions and uncertainty, including the current volatility in financial markets, is adding a substantial amount of risk to the North American and worldwide economy, and the continuation of such factors may adversely impact the Corporation's anticipated or expected results of operations and may cause the actual results to materially deviate from the forward-looking information contained in this annual information form.

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 prior to the consideration of how those activities are financed or how the results are taxed. Investors should be cautioned that these measures should not be construed as an alternative to net income, 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 asset retirement 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 boe basis that comprise funds from operations.

ADVANTAGE OIL & GAS LTD.

General

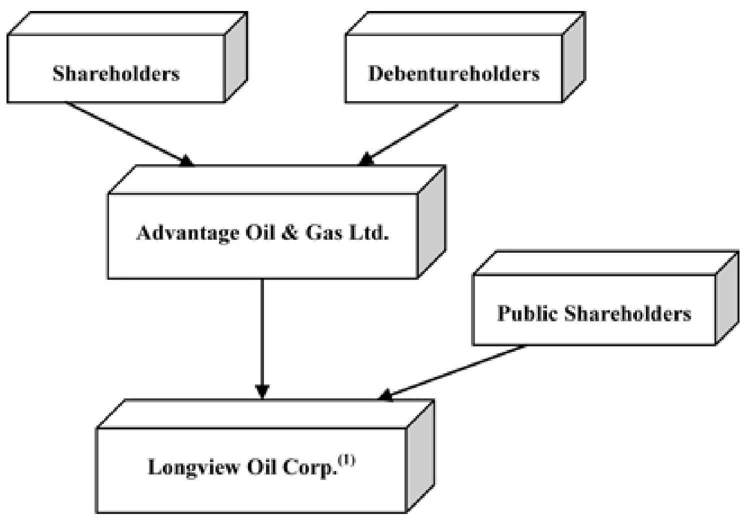
The Corporation was formed pursuant to the amalgamation of Advantage Oil & Gas Ltd., 1335703 Alberta Ltd., SET Resources Inc. and Sound ExchangeCo Ltd. under the ABCA on September 5, 2007. On July 9, 2009 the articles of the Corporation were amended in connection with the Trust Conversion to change the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

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

The head office of AOG is located at Suite 700, 400 – 3rd Avenue S.W., Calgary, Alberta T2P 4H2 and its registered office is located at 2400, 525 – 8th Avenue S.W., Calgary, Alberta T2P 1G1.

Corporate Structure

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



Note:

(1) On April 14, 2011, Advantage's subsidiary, Longview Oil Corp., completed its initial public offering of common shares (the "**Longview Offering**") and purchased certain oil-weighted assets from Advantage for consideration comprised of cash and 29,450,000 common shares (the "**Longview Transaction**"). As a result of the Longview Offering and the Longview Transaction, Advantage currently holds approximately 63% of the common shares of Longview and the remaining 37% is held by public shareholders. See "*General Development of the Business – 2011*".

GENERAL DEVELOPMENT OF THE BUSINESS

General

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

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

Three Year History

2009

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

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

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

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

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

On June 15, 2009, the Trust announced that it had signed two purchase and sale agreements relating to the disposition of $252.6 million of assets. The disposition price for one package (the "**Package One Assets**") of the Sale Assets was $176 million, subject to customary adjustments. The Package One Assets were producing as of June 15, 2009 approximately 5,900 boe/d and proved plus probable reserves of the Package One Assets were estimated by Sproule to be 18.8 MMboe as of March 31, 2009. The closing of the sale of the Package One Assets occurred on July 24, 2009, with an April 1, 2009 effective date. The disposition price for the second package (the "**Package Two Assets**") of the Sale Assets was $76.6 million, subject to customary adjustments. The Package Two Assets were producing as of June 15, 2009 approximately 2,200 boe/d and proved plus probable reserves of the Package Two Assets were estimated by Sproule to be 8.5 MMboe as of March 31, 2009. The closing of the sale of the Package Two Assets occurred on July 15, 2009, with an April 1, 2009 effective date.

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

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

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

On August 13, 2009, in connection with completion of the Trust Conversion and Disposition of Assets, the Corporation's credit facilities were amended to be a $525 million facility comprised of a $20 million revolving operating loan facility and a $505 million extendible revolving credit facility (the "**Credit Facilities**"). Various borrowing options are available under the Credit Facilities, including prime rate based advances, U.S. base rate advances, U.S. dollar LIBOR advances and bankers' acceptances loans. The Credit Facilities are secured by a $1 billion floating charge demand debenture, a general security agreement and a subordination agreement from the Corporation covering all assets and cash flows. The amounts available to the Corporation from time to time under the Credit Facilities are based upon the borrowing base determined by the lenders and which is redetermined on a semi-annual basis by those lenders with the next redetermination anticipated to take place in June 2010. The borrowing base constitutes a revolving facility for a 364 day term which is extendible annually for a further 364 day revolving period, subject to a one year term maturity as to lenders not agreeing to such annual extension.

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

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

2010

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

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

On May 10, 2010, the Corporation announced that it had signed purchase and sale agreements relating to the disposition of non-core natural gas weighted assets located in South Eastern Alberta for gross cash proceeds of $67 million, subject to customary adjustments. The disposition was comprised of two separate transactions which included combined production of approximately 1,700 boe/d (80% natural gas) and proved plus probable reserves of 6.4 MMboe as at December 31, 2009. The transactions closed on May 31, 2010 and June 3, 2010 with effective dates of March 1, 2010 and April 1, 2010, respectively. The net proceeds from these dispositions were initially used to repay bank indebtedness under the Credit Facilities.

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

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

2011

Longview Offering and Longview Transaction

On April 14, 2011, Longview completed the Longview Offering and completed the acquisition of certain oil-weighted assets (the "**Acquired Assets**") of the Corporation located in West Central Alberta, Southeast Saskatchewan and the Lloydminster area of Saskatchewan. Pursuant to the Longview Offering, Longview issued 15,000,000 common shares at $10.00 per common share for aggregate gross proceeds of $150,000,000. The over-allotment option granted by Longview to the underwriters pursuant to the Longview Offering to purchase up to an additional 2,250,000 common shares at a purchase price of $10.00 per common share was exercised in full on April 28, 2011.

The purchase price for the Longview Transaction was approximately $554.1 million, prior to closing adjustments pursuant to the terms of the purchase and sale agreement for the Acquired Assets. The purchase price for the Acquired Assets was comprised of the net proceeds of the Longview Offering (including the net proceeds from the exercise of the over-allotment option) in the amount of $162.1 million, the issuance of 29,450,000 common shares to the Corporation and approximately $83.4 million drawn from Longview's credit facilities. As a result of the Longview Offering and the Longview Transaction, Advantage retained an equity ownership interest of approximately 63% of the common shares of Longview. See "*Statement of Reserves Data and Other Oil & Gas Information - Ownership of Longview - Interests of Minority Shareholders in Longview Reserves*".

Concurrent with closing of the Longview Offering, AOG entered into a Technical Services Agreement (the "**TSA**") with Longview. Under the TSA, AOG provides the necessary personnel and technical services to manage Longview's business and Longview reimburses AOG on a monthly basis for its share of administrative charges based on respective levels of production. Longview has an independent board of directors and the officers of Longview are Kelly Drader (President and Chief Executive Officer), Craig Blackwood (Chief Financial Officer), Andy Mah (Chief Operating Officer), Patrick Cairns (Senior Vice President), Neil Bokenfohr (Vice President, Exploitation) and Weldon Kary (Vice President, Geosciences and Land). The officers of Longview provide services to Longview under the TSA but remain as employees of Advantage. See "*Material Contracts*".

In connection with the Longview Transaction, on April 14, 2011, Longview entered into a credit agreement with a syndicate of financial lenders for an extendible revolving credit facility in the maximum principal amount of $180 million as well as an operating credit agreement with a Canadian financial institution in the maximum principal amount of $20 million (collectively, the "**Longview Credit Facilities**"). See "*Material Contracts*".

As a result of the sale of the assets pursuant to the Longview Transaction, Advantage's borrowing base under its Credit Facilities was reduced to $275 million.

Other Developments

On July 4, 2011, the Board of Directors of AOG approved a capital and operating budget for the twelve month period ending June 30, 2012. The capital budget is focused on a Phase IV development program at Glacier with two key objectives to: (i) increase throughput capacity at the Glacier gas plant from 100 MMcf/d to 140 MMcf/d by Q2 2012 and drill a sufficient number of wells to fill the plant; and (ii) further evaluate the Middle and Lower Montney formations.

On December 20, 2011 the board of directors of Longview approved operational guidance and a capital budget of approximately $73 million for the year ending December 31, 2012. The capital budget will be primarily focused on oil or oil with liquids rich solution gas projects.

Recent Developments

On March 22, 2012 Advantage announced that, due to the prevailing low natural gas pricing environment, production at Glacier will be maintained between 90 MMcf/d to 100 MMcf/d and interim guidance was issued for the six months ending June 30, 2012.

Anticipated Changes in the Business

As at the date hereof, we do not anticipate that any material change in our business will occur during the balance of the 2012 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, 2011 for which disclosure is required under Part 8 of National Instrument of 51-102 *Continuous Disclosure Obligations*.

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

DESCRIPTION OF OUR BUSINESS AND OPERATIONS

General

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

Advantage's exploitation and development program is focused primarily at Glacier, Alberta where it is developing a significant natural gas resource play. As current and future practice, AOG has established a financial hedging strategy and may manage the risk associated with changes in commodity prices by entering into derivatives. See "*Risk Factors*". Although Advantage has a significant capital development program, we also actively pursue growth opportunities through oil and gas asset acquisitions, as well as through corporate acquisitions. AOG targets acquisitions that are accretive to net asset value and that increase our reserve and production base per Common Share outstanding. Acquisitions must also meet reserve life index criteria and exhibit low risk opportunities to increase reserves and production. It is currently intended that AOG will finance acquisitions and investments through the Credit Facilities, the issuance of additional Common Shares from treasury and the issuance of subordinated convertible debentures, maintaining prudent leverage.

Reorganizations

As at the date hereof, other than the Trust Conversion and the Longview Transaction, there have been no material reorganizations of the Trust or AOG and or any of our subsidiaries within the three most recently completed financial years or proposed for the current financial year. See "*General Development of the Business*".

Bankruptcy and Similar Procedures

There have been no bankruptcy, receivership or similar proceedings against the Corporation or any of its subsidiaries or related entities, or any voluntary 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.

Human Resources

As at December 31, 2011, the Corporation employed 125 full-time employees, 99 of which are located in the head office and 26 of which are located in the field. We also retained 19 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, 2011. The effective date of the Statement is December 31, 2011 and the preparation date of the Statement is March 9, 2012.

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, 2011 contained in a consolidated report of Sproule dated March 9, 2012 (the "**Sproule Report**"). The Sproule Report evaluated, as at December 31, 2011, the oil, NGLs and natural gas reserves of AOG and its consolidated subsidiaries, including Longview. 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. In accordance with NI 51-101, the Sproule Report includes 100% of the reserves and future net revenue attributable to Longview's properties, without reduction to reflect the approximately 37% third-party minority interests in Longview. Accordingly, the Reserves Data for the Corporation's consolidated reserves set forth below, which has been derived from the Sproule Report, reflects 100% of Longview's reserves and future net revenue without reduction to reflect the Longview Non-Controlling Interest. Approximately 5.4% of the assigned total gross proved plus probable reserves and 12.2% of the total gross proved plus probable future net revenue discounted at 10% in the Sproule Report is attributable to the Longview Non-Controlling Interest. See "*Statement of Reserves Data and Other Oil & Gas Information - Ownership of Longview - Interests of Minority Shareholders in Longview Reserves*".

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 provinces of Alberta and Saskatchewan.

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, 2011
FORECAST PRICES AND COSTS

RESERVES CATEGORY[1]	RESERVES LIGHT AND MEDIUM OIL Gross (Mbbl)	Net (Mbbl)	HEAVY OIL Gross (Mbbl)	Net (Mbbl)
PROVED				
Developed Producing	9,966.1	8,764.8	1,457.9	1,341.0
Developed Non-Producing	417.7	359.1	157.2	138.4
Undeveloped	3,767.8	3,331.3	451.6	377.2
TOTAL PROVED	14,151.70	12,455.20	2,066.6	1,856.6
PROBABLE	10,293.8	8,707.7	2,999.4	2,456.0
TOTAL PROVED PLUS PROBABLE	24,445.6	21,162.9	5,066.0	4,312.5

RESERVES CATEGORY[1]	RESERVES NATURAL GAS Gross (MMcf)	Net (MMcf)	NATURAL GAS LIQUIDS Gross (Mbbl)	Net (Mbbl)
PROVED				
Developed Producing	264,178	243,263	3,604.30	2,717.00
Developed Non-Producing	17,923	16,907	56.9	44.2
Undeveloped	562,421	530,424	512.2	409.2
TOTAL PROVED	844,523	790,595	4,173	3,170
PROBABLE	473,197	441,454	2,133	1,586.1
TOTAL PROVED PLUS PROBABLE	1,317,720	1,232,049	6,307	4,756

RESERVES CATEGORY[1]	RESERVES TOTAL OIL EQUIVALENT Gross (Mboe)	Net (Mboe)
PROVED		
Developed Producing	59,058.0	53,366.6
Developed Non-Producing	3,619.0	3,359.5
Undeveloped	98,468.4	92,521.7
TOTAL PROVED	161,145.5	149,248.0
PROBABLE	94,293.3	86,325.5
TOTAL PROVED PLUS PROBABLE	255,438.8	235,573.5

Note:

(1) All reserves presented herein represent the Corporation's and the Corporation's consolidated subsidiaries interest. The Reserves Data reflects 100% of Longview's reserves and future net revenue without reduction to reflect the Longview Non-Controlling Interest. As at December 31, 2011, the Corporation held an approximately 63% interest in Longview. For further discussion see "*Statement of Reserves Data and Other Oil & Gas Information - Ownership of Longview - Interests of Minority Shareholders in Longview Reserves*".

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
as at December 31, 2011
FORECAST PRICES AND COSTS

RESERVES CATEGORY[2]	Before Income Tax Discounted at (%/year) 0% ($000's)	5% ($000's)	10% ($000's)	15% ($000's)	20% ($000's)	After Income Taxes Discounted at (%/year) 0% ($000's)	5% ($000's)	10% ($000's)	15% ($000's)	20% ($000's)	Unit Value Before Income Tax Discounted at 10%/ year[1] ($/boe)
PROVED											
Developed Producing	1,279,093	985,496	806,117	685,863	599,896	1,279,093	985,496	806,117	685,863	599,896	15.11
Developed Non-Producing	88,980	64,648	50,517	41,299	34,822	82,954	60,841	48,019	39,608	33,645	15.04
Undeveloped	1,717,981	892,738	488,488	265,125	131,962	1,355,424	701,501	375,675	193,119	83,173	5.28
TOTAL PROVED	3,086,055	1,942,882	1,345,123	992,289	766,679	2,717,471	1,747,839	1,229,812	918,590	716,714	9.01
PROBABLE	2,964,965	1,446,995	866,957	581,677	417,947	2,209,260	1,077,579	645,178	432,774	310,924	10.04
TOTAL PROVED PLUS PROBABLE	6,051,020	3,389,877	2,212,080	1,573,965	1,184,626	4,926,731	2,825,418	1,874,990	1,351,364	1,027,638	9.39

Notes:

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

(2) All reserves presented herein represent the Corporation's and the Corporation's consolidated subsidiaries interest. The Reserves Data reflects 100% of Longview's reserves and future net revenue without reduction to reflect the Longview Non-Controlling Interest. As at December 31, 2011, the Corporation held an approximately 63% interest in Longview. For further discussion see "*Statement of Reserves Data and Other Oil & Gas Information - Ownership of Longview - Interests of Minority Shareholders in Longview Reserves*".

(3) 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, 2011.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
as at December 31, 2011
FORECAST PRICES AND COSTS

RESERVES CATEGORY[1]	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 INCOME TAXES ($000's)	FUTURE INCOME TAXES ($000's)	FUTURE NET REVENUE AFTER INCOME TAXES ($000's)
Proved Reserves	7,081,309	572,831	2,070,081	1,265,695	86,647	3,086,054	368,584	2,717,471
Proved Plus Probable Reserves	12,237,504	1,057,595	3,346,645	1,655,724	126,520	6,051,020	1,124,289	4,926,731

Note:

(1) All reserves presented herein represent the Corporation's and the Corporation's consolidated subsidiaries interest. The Reserves Data reflects 100% of Longview's reserves and future net revenue without reduction to reflect the Longview Non-Controlling Interest. As at December 31, 2011, the Corporation held an approximately 63% interest in Longview. For further discussion see "*Statement of Reserves Data and Other Oil & Gas Information - Ownership of Longview - Interests of Minority Shareholders in Longview Reserves*".

FUTURE NET REVENUE
BY PRODUCTION GROUP
as at December 31, 2011
FORECAST PRICES AND COSTS

RESERVES CATEGORY[1]	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)	401,710	26.22
	Heavy Oil (including solution gas and other by-products)	50,726	24.65
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	873,519	6.76
	Non-Conventional Oil and Gas Activities (Coalbed Methane)	19,168	7.21
	TOTAL	1,345,123	9.01
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	635,945	24.86
	Heavy Oil (including solution gas and other by-products)	106,048	23.02
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	1,444,238	7.16
	Non-Conventional Oil and Gas Activities (Coalbed Methane)	25,848	7.20
	TOTAL	2,212,079	9.39

Note:

(1) All reserves presented herein represent the Corporation's and the Corporation's consolidated subsidiaries interest. The Reserves Data reflects 100% of Longview's reserves and future net revenue without reduction to reflect the Longview Non-Controlling Interest. As at December 31, 2011, the Corporation held an approximately 63% interest in Longview. For further discussion see "*Statement of Reserves Data and Other Oil & Gas Information - Ownership of Longview - Interests of Minority Shareholders in Longview Reserves*".

Pricing Assumptions

The following tables set forth the benchmark reference prices, as at December 31, 2011, 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, 2011
FORECAST PRICES AND COSTS

Year	WTI Cushing Oklahoma ($US/bbl)	Light Sweet Crude Oil at Edmonton 40° API ($Cdn/bbl)	Medium Crude Oil 29° API ($Cdn/bbl)	Hardisty Heavy 12° API ($Cdn/bbl)	NATURAL GAS AECO-C Spot ($Cdn/ MMBtu)	NATURAL GAS LIQUIDS Edmonton Pentanes Plus ($Cdn/bbl)	NATURAL GAS LIQUIDS Edmonton Butanes ($Cdn/bbl)	INFLATION RATES %/Year	EXCHANGE RATE (2) ($US/$Cdn)
2011	95.00	95.16	87.86	69.10	3.72	104.12	70.93	1.5	1.012
Forecast(3)									
2012	98.07	96.87	90.09	74.59	3.16	103.57	72.20	2.0	1.012
2013	94.90	93.75	87.19	72.19	3.78	100.23	69.87	2.0	1.012
2014	92.00	90.89	84.52	69.98	4.13	97.17	67.74	2.0	1.012
2015	97.42	96.23	89.5	74.10	5.53	102.89	71.73	2.0	1.012
2016	99.37	98.16	91.29	75.58	5.65	104.94	73.16	2.0	1.012
2017	101.35	100.12	93.11	77.09	5.77	107.04	74.63	2.0	1.012
2018	103.38	102.12	94.98	78.64	5.89	109.18	76.12	2.0	1.012
2019	105.45	104.17	96.88	80.21	6.01	111.37	77.64	2.0	1.012
2020	107.56	106.25	98.81	81.81	6.14	113.59	79.19	2.0	1.012
2021	109.71	108.38	100.79	83.45	6.27	115.87	80.78	2.0	1.012
Thereafter	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%		

Notes:

(1) This summary table identifies benchmark reference pricing schedules that might apply to a *reporting issuer*.
(2) The exchange rate used to generate the benchmark reference prices in this table.
(3) As at December 31.

Weighted average historical prices, including hedging, realized by us for the year ended December 31, 2011, were $4.17/Mcf for natural gas, $85.38/bbl for crude oil, and $65.64/bbl for NGLs.

Reconciliations of Changes in Reserves

The following table sets forth a reconciliation of the Corporation's total gross proved, gross probable and total gross proved plus probable reserves as at December 31, 2011 against such reserves as at December 31, 2010 based on forecast prices and cost assumptions.

RECONCILIATION OF GROSS RESERVES(1) BY PRODUCT TYPE FORECAST PRICES AND COSTS

FACTORS	Light And Medium Oil Proved (Mbbl)	Light And Medium Oil Probable (Mbbl)	Light And Medium Oil Proved Plus Probable (Mbbl)	Heavy Oil Proved (Mbbl)	Heavy Oil Probable (Mbbl)	Heavy Oil Proved Plus Probable (Mbbl)	Natural Gas Liquids Proved (Mbbl)	Natural Gas Liquids Probable (Mbbl)	Natural Gas Liquids Proved Plus Probable (Mbbl)
December 31, 2010	13,862.1	10,182.3	24,044.5	1,654.0	2,833.1	4,487.0	5,181.1	2,614.8	7,795.9
Extensions	357.0	321.4	678.4	276.3	120.6	396.9	20.1	7.9	28.0
Improved Recovery	1,654.2	1,606.8	3,261.0	123.8	137.8	261.6	93.8	73.6	167.4
Infill Drilling	-	-	-	-	-	-	-	-	-
Technical Revisions	(261.7)	(1,832.4)	(2,094.1)	266.3	(101.8)	164.5	(440.0)	(539.9)	(979.9)
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	1.2	0.4	1.6
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	7.9	15.7	23.6	-2.2	9.8	7.6	(128.5)	(23.0)	(151.5)
Production	(1,467.8)	-	(1,467.8)	(251.6)	0.0	(251.6)	(554.3)	-	(554.3)
December 31, 2011	14,151.7	10,293.8	24,445.6	2,066.6	2,999.4	5,066.0	4,173.4	2,133.9	6,307.2

FACTORS	Associated and Non-Associated Gas Proved (MMcf)	Associated and Non-Associated Gas Probable (MMcf)	Associated and Non-Associated Gas Proved Plus Probable (MMcf)	Natural Gas - Solution Proved (MMcf)	Natural Gas - Solution Probable (MMcf)	Natural Gas - Solution Proved Plus Probable (MMcf)
December 31, 2010	696,919	486,069	1,182,989	18,985	13,023	32,008
Extensions	11,936	17,021	28,957	549	48	597
Improved Recovery	15,819	4,928	20,747	1,614	1,809	3,423
Infill Drilling	-	-	-	-	-	-
Technical Revisions	147,799	-50,239	97,560	(1,684)	(4,925)	(6,609)
Discoveries	-	-	-	-	-	-
Acquisitions	19	8	27	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	(19,583)	(890)	(20,473)	11	21	32
Production	(42,720)	-	(42,720)	(2,720)	-	(2,720)
December 31, 2011	810,189	456,898	1,267,087	16,755	9,976	26,731

FACTORS	Coalbed Methane WI Proved (MMcf)	WI Probable (MMcf)	WI Proved Plus Probable (MMcf)	Oil Equivalent WI Proved (MBoe)	WI Probable (MBoe)	WI Proved Plus Probable (MBoe)
December 31, 2010	20,136	8,836	28,972	143,370.5	100,284.9	243,655.6
Extensions	266	87	353	2,778.6	3,309.2	6,087.8
Improved Recovery	-	-	-	4,777.3	2,941.0	7,718.3
Infill Drilling	-	-	-	-	-	-
Technical Revisions	(426)	(2,500)	(2,926)	23,846.1	(12,084.8)	11,761.3
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	4.4	1.7	6.1
Dispositions	-	-	-	-	-	-
Economic Factors	(360)	(99)	(459)	(3,444.8)	(158.8)	(3,603.6)
Production	(2,038)	-	(2,038)	(10,186.7)	-	(10,186.7)
December 31, 2011	17,578	6,324	23,902	161,145.4	94,293.4	255,438.8

Note:

(1) All reserves presented herein represent the Corporation's and the Corporation's consolidated subsidiaries interest. The Reserves Data reflects 100% of Longview's reserves and future net revenue without reduction to reflect the Longview Non-Controlling Interest. As at December 31, 2011, the Corporation held an approximately 63% interest in Longview. For further discussion see "*Statement of Reserves Data and Other Oil & Gas Information - Ownership of Longview - Interests of Minority Shareholders in Longview Reserves*".

Ownership of Longview - Interests of Minority Shareholders in Longview Reserves

On April 14, 2011, Longview completed the Longview Offering and the Longview Transaction. The purchase price for the Longview Transaction was approximately $554.1 million, prior to closing adjustments pursuant to the terms of the purchase and sale agreement for the Acquired Assets. The purchase price for the Acquired Assets was comprised of the net proceeds of the Longview Offering (including the net proceeds from the exercise of the over-allotment option) in the amount of $162.1 million, the issuance of 29,450,000 common shares to the Corporation and approximately $83.4 million drawn from Longview's credit facilities. As a result of the Longview Offering and the Longview Transaction, as at December 31, 2011, the Corporation held an approximately 63% equity interest in Longview.

As at December 31, 2011, the Sproule Report estimated Longview's share of proved, probable and proved plus probable reserves, representing 100% of the working interest of Longview, which were consolidated in the Corporation's reserves. Third-party minority shareholders indirectly owned approximately 37% of these reserves at December 31, 2011. The tables below represent a summary of reserves indirectly owned by Longview's third-party minority shareholders and a summary of the net present value (before tax) of such reserves, all as at December 31, 2011. All reserves stated herein are based on forecast prices and costs.

SUMMARY OF OIL AND GAS RESERVES
as at December 31, 2011
FORECAST PRICES AND COSTS

RESERVES CATEGORY	RESERVES			
	LIGHT AND MEDIUM OIL		HEAVY OIL	
	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)
PROVED				
Developed Producing	3,178.8	2,804.0	537.1	489.5
Developed Non-Producing	140.4	122.2	58.2	51.2
Undeveloped	1,376.3	1,218.2	167.1	139.6
TOTAL PROVED	4,695.5	4,144.5	762.3	680.2
PROBABLE	3,487.0	2,970.9	1,108.0	905.4
TOTAL PROVED PLUS PROBABLE	8,182.5	7,115.4	1,870.4	1,585.7

RESERVES CATEGORY	RESERVES			
	NATURAL GAS		NATURAL GAS LIQUIDS	
	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
PROVED				
Developed Producing	7,307	6,542	455.1	339.0
Developed Non-Producing	246	216	18.4	14.4
Undeveloped	2,341	2,142	79.8	62.5
TOTAL PROVED	9,895	8,901	553.3	415.8
PROBABLE	7,746	6,915	358.5	266.9
TOTAL PROVED PLUS PROBABLE	17,640	15,815	911.8	682.8

RESERVES CATEGORY	RESERVES	
	TOTAL OIL EQUIVALENT	
	Gross (Mboe)	Net (Mboe)
PROVED		
Developed Producing	5,388.9	4,722.9
Developed Non-Producing	257.9	223.9
Undeveloped	2,013.4	1,777.2
TOTAL PROVED	7,660.2	6,724.0
PROBABLE	6,244.5	5,295.7
TOTAL PROVED PLUS PROBABLE	13,904.7	12,019.7

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
as at December 31, 2011
FORECAST PRICES AND COSTS

RESERVES CATEGORY	Before Income Tax Discounted at (%/year) 0% ($000's)	5% ($000's)	10% ($000's)	15% ($000's)	20% ($000's)	After Income Taxes Discounted at (%/year) 0% ($000's)	5% ($000's)	10% ($000's)	15% ($000's)	20% ($000's)	Unit Value Before Income Tax Discounted at 10%/ year(1) ($/boe)
PROVED											
Developed Producing	200,422	149,772	122,021	104,182	91,636	200,422	149,772	122,021	104,182	91,632	25.84
Developed Non-Producing	9,015	6,930	5,637	4,751	4,104	6,785	5,521	4,713	4,125	3,668	25.18
Undeveloped	63,675	45,231	33,072	24,643	18,565	46,645	32,485	23,174	16,741	12,115	18.61
TOTAL PROVED	273,112	201,932	160,730	133,576	114,305	253,853	187,778	149,908	125,048	107,419	23.90
PROBABLE	272,679	161,502	108,779	79,198	60,673	200,078	117,897	78,715	56,703	42,929	20.54
TOTAL PROVED PLUS PROBABLE	545,791	363,434	269,508	212,774	174,977	453,931	305,674	228,623	181,751	150,348	22.42

Note:

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

Additional Information Relating to Reserves Data

Unless otherwise indicated, the additional information contained in this section pertains to Advantage and Longview on a consolidated basis and references to Advantage include Longview (without reduction to reflect the Longview Non-Controlling Interest). See "*Statement of Reserves Data and Other Oil & Gas Information - Ownership of Longview - Interests of Minority Shareholders in Longview Reserves*".

Undeveloped Reserves

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

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

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

Proved Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
	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	312	3,730	-	312	45,506	116,503	363	1,143
2009	44	2,615	-	185	166,681	297,598	7	606
2010	210	2,795	-	90	270,670	499,783	42	621
2011	1,391	3,768	311	452	88,461	562,421	5	512

Sproule has assigned 98.5 MMboe of gross proved undeveloped reserves in the Sproule Report under forecast prices and costs, together with $1,256.5 million of associated undiscounted future capital expenditures. Proved undeveloped capital spending in the first two forecast years of the Sproule Report accounts for $319.2 million, or 25.4%, of the total forecast. These figures increase to $916.4 million or 72.9%, during the first five years of the Sproule Report.

Probable Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
	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	243	7,382	-	2,452	88,131	171,081	582	1,577
2009	23	8,221	-	2,382	391,172	546,217	3	774
2010	656	5,069	-	2,121	91,205	409,478	27	742
2011	1,636	6,212	125	2,152	23,940	360,510	12	756

Sproule has assigned 69.2 MMboe of gross probable undeveloped reserves and has allocated future development capital of $385.7 million to all gross probable undeveloped reserves with $221.7 million scheduled for the first five years.

Significant Factors or Uncertainties

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

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

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

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

Future Development Costs

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

	Forecast Prices and Costs	
Year	Proved Reserves (MM$)	Proved Plus Probable Reserves (MM$)
2012	123.0	183.3
2013	202.7	256.9
2014	265.4	299.6
2015	230.9	285.7
2016	102.2	122.4
Total: Undiscounted for all years	1,265.7	1,655.7

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

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

Other Oil and Gas Information

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

AOG's properties can be divided on the broad basis of commodity and of production type. Light or medium gravity oil accounts for 22% of Total Current Production and 10% of gross proved reserves, and natural gas accounts for 78% of Total Current Production and 86% of gross proved reserves.

The following property descriptions are as of March 23, 2012 unless otherwise noted and reserves quoted are as reported in the Sproule Report.

Property Descriptions

Advantage Oil and Gas Major Properties

Glacier, Alberta

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

In 2011, Advantage drilled and completed 24 gross (23.5 net) horizontal wells in the Montney and Lower Doig formations on the Glacier property. Subsequent to year end and prior to spring breakup Advantage will have drilled an additional 8 gross (8 net) horizontal Montney/Doig wells. Since the spud of the first horizontal well on July 26, 2008, Advantage has drilled 98 gross (89.9 net) horizontal wells at the Glacier property. One vertical well, drilled in 2010, into the underlying Belloy Formation was completed for use as an acid gas disposal well and one existing vertical well proximal to the 05-02 main compression facility was recompleted as a service well for water disposal purposes.

Although Advantage has utilised a number of completion techniques, to date, the majority of the wells have been completed using an abrasa-jet and sand plug completion technique in wellbores which are cased to total depth. On average 12 fracs per horizontal well have been placed in the wells to date with as many as 18 in the longer horizontal wells. The fracs are water and CO2 fracs carrying on average 75 tonnes of sand per frac. All of the wells drilled by Advantage have been completed with the exception of the last portion of the Phase IV wells which will be completed following spring breakup 2012. Test rates per well in the Doig (Upper Montney) have been improving from 3.7 MMcf/d for the 8 wells in the Phase I (2008-2009) program through 7.3 MMcf/d for the 25 wells in the Phase II (2009-2010) program to 8.0 MMcf/d for the 24 wells in the Phase III program and the initial 10 wells in Phase IV. These rates are average wellhead rates all normalized to 435 psi. Current Production of 100 MMcf/d or 16,667 boe/d represents over 50% of the Corporation's Total Current Production.

In the second quarter of 2011 Advantage completed the Phase III expansion of capacity at its 5-02 gas compression facility to 100 MMcf/d from 50 MMcf/d. With the completion of the acid gas disposal well and installation of acid gas compression at the 5-02 facility, Advantage has discontinued flaring of acid gas. All gas is sold through Advantage’s 22 kilometer sales pipeline into the TransCanada pipeline system. Advantage is currently concluding Phase IV expansion which will increase available capacity to 135 MMcf/d. Operating costs have dropped from a high of $5.80/mcf at the start of the project to just under $0.30/mcf at year end 2011. 2011 exit rate sales production was 99.3 MMcf/d from the 5-02 facility.

The Sproule Report assigns 701 bcf of gross proved natural gas reserves and 401 bcf of gross probable natural gas reserves to this property.

Southern Alberta

Lookout Butte, Alberta

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

The Sproule Report assigns 24.3 bcf of gross proved natural gas reserves and 80.7 Mbbls of gross proved crude oil and NGL reserves to Lookout Butte. In addition, 13.0 bcf of gross probable natural gas reserves and 87.4 Mbbls of gross probable crude oil and NGL reserves have been assigned to this property.

Medicine Hat, Alberta

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

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

The Sproule Report assigns 17.0 bcf of gross proved natural gas reserves to the Medicine Hat property. In addition, 14.0 bcf of gross probable natural gas reserves have been assigned to this property.

West Central Alberta

Willesden Green (Open Lake), Alberta

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

The Sproule Report assigns 3.4 bcf of gross proved natural gas reserves and 505 Mbbls of gross proved crude oil and NGL reserves to the Willesden Green property. In addition, 1.6 bcf of gross probable natural gas reserves and 225 Mbbls of gross probable crude oil and NGL reserves have been assigned to this property.

Brazeau -Ferrier, Alberta

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

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

The Sproule Report assigns 5.1 bcf of gross proved natural gas reserves and 445 Mbbls of gross proved crude oil and NGL reserves to the Brazeau River area. In addition, 1.9 bcf of gross probable natural gas reserves and 210 Mbbls of gross probable crude oil and NGL reserves have been assigned to this area.

Northeast and East Central Alberta

Chigwell and Oberlin (Nevis), Alberta

Advantage has two coal bed methane ("**CBM**") fields in the Chigwell and Oberlin (Nevis) areas of Alberta which produce natural gas from Horseshoe Canyon Formation coal beds and adjacent associated sandstones. These fields lie approximately 60 kilometers northeast and east of the City of Red Deer Alberta respectively. The wells on these fields are completed on a commingled basis in multiple layers of individual coals which range in thickness from 1 to

3 meters along with associated and adjacent gas charged sandstones. The fields are for the most part developed on the basis of 4 vertical wells per section. These wells are shallow with completed intervals ranging between 150 and 550 meters in depth. The wells are connected with low pressure gathering system to central compression facilities which allows the fields to be drawn down to very low operating pressure of between 35 and 70 kpa. Advantage operates the Oberlin property with 31 gross and 24.5 net sections. The Chigwell property is a combination of operated and nonoperated with a wide range of working interests across 27.5 gross (11.25 net) sections. Current Production from these fields is 1,689 boe/d.

The Sproule Report assigns 20.1 bcf of gross proved natural gas reserves to these CBM properties. In addition, 7.7 bcf of gross probable natural gas reserves have been assigned to this area.

Northeastern Shallow Gas

Advantage has shallow gas properties located in the eastern side of Alberta, including the Wainwright property, which is located north of the town of Wainwright, and the Tweedie and Cache properties which are located west of the town of Bonnyville. These properties produce from multiple horizons generally all at depths of 750 meters or less. The principle producing intervals are Cretaceous Mannville Formation sands, Viking Formation sands and Second White Specks sands and silts. Current Production from these fields is 726 boe/d.

The Sproule Report assigns 10.5 bcf of gross proved natural gas reserves and 6.2 Mbbls of gross proved crude oil and NGL reserves to these fields. In addition, 2.8 bcf of gross probable natural gas reserves and 4.8 Mbbls of gross probable crude oil and NGL reserves have been assigned.

Longview Oil and Gas Major Properties

West Central Alberta

This area consists of a number of individual properties and lands located in the West Central area of Alberta. Current Production from this area is approximately 4,320 boe/d and is comprised mainly of low decline, high netback light oil with average API gravity of 34^o. Production is derived from numerous large oil pools where opportunities exist to increase production and reserves through low risk development drilling and the application of enhanced oil recovery techniques. Drilling opportunities also exist for step-out and exploration drilling on undeveloped lands.

Nevis, Alberta

Nevis is an operated property consisting of approximately 44 gross (34.6 net) sections of land which are situated 60 kilometres east of Red Deer, Alberta. Nevis is Longview's largest producing property with Current Production of approximately 2,219 boe/d. The property is divided into two main pools each trapped structurally and stratigraphically with an associated updip gas cap to each pool. Crude oil quality averages 39^o API which also produces associated natural gas and NGLs. Two operated facilities are utilized for processing the oil and natural gas production which is gathered from the wells through pipelines to the respective central facilities. Clean oil is trucked from the facilities and water is disposed of back into the reservoir. Associated gas is transported through pipelines to third party compression and sales.

The main producing zone is the Devonian age Wabamun Formation, which occur at 1,600 metres of depth. This reservoir is a high porosity, low permeability carbonate which results in relatively low production inflow from vertical wells. As a result, horizontal drilling technology is used to access additional inflow from the low permeability rock with current development drilling downspacing to six wells per section. Production has increased and the ultimate recovery has been enhanced through increased well density as a result of receiving regulatory approval to downspace sections of this property. Horizontal well laterals are on average 1,200 metres in length. Wells are completed on an open hole basis and only require an acid wash as stimulation to clean the wellbore before being placed on production.

In the eastern pool, a pilot waterflood scheme has been started to evaluate the potential for enhanced recovery of these pools in order to access the large oil-in place which is not being drained through primary development. Longview is also studying the implementation of CO_2 flood applications to enhance production recovery and reserves at Nevis.

The Sproule Report assigns 6.8 bcf of gross proved natural gas reserves and 3,085.9 Mbbls of gross proved crude oil and NGL reserves to this property. In addition, 2.4 bcf of gross probable natural gas reserves and 1,431.3 Mbbls of gross probable crude oil and NGL reserves have been assigned to this property.

Westerose, Alberta

The Westerose property is located approximately 60 kilometres southwest of Edmonton, Alberta and consists mainly of the Westerose Banff "C" Unit, Chip Lake, interests in several Pembina Cardium oil units and other liquids rich natural gas production in areas surrounding the Westerose Banff "C" Unit. Current Production at Westerose area is approximately 634 boe/d.

Westerose Banff "C" Unit

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

Chip Lake, Alberta

The Chip Lake property is located 125 kilometres west of Edmonton, Alberta. Longview holds a 100% working interest in seven sections of land with Current Production of approximately 212 boe/d from the Rock Creek Formation. The field consists of 12 producing vertical oil wells, four water injection wells and a central oil processing battery and water disposal facility. Associated natural gas is compressed and sold through third party facilities where nautral gas liquids (35 bbls/MMcf) are extracted and sold. Clean oil is trucked for sale.

The Rock Creek Formation is a conventional sandstone reservoir in which 40º API oil is trapped against an updip shale plug channel that truncates the reservoir which occurs at a depth of 1,850 metres. Pay thickness is in excess of eight metres along the axis of the reservoir and it is there and along the updip margin that infill drilling, potentially with a combination of vertical and horizontal wells, will be targeted after water injection has re-pressured this area of the pool. The water injection scheme is currently being optimized and regulatory and spacing work is proceeding to allow for additional wells or conversion of existing wells into water injectors.

Cardium properties, West Central Alberta

The Cardium Formation properties lie in the west central Alberta basin primarily between Townships 38 and 48, Ranges 2 to 11W5. These properties consist of a variety of lands with working interests ranging between 8% and 100% with an average working interest of 32%. Most of the properties are non-operated with the exception of the Pembina Rose Creek Cardium Unit, which is an operated Cardium producing property consisting of 1,600 acres of 100% unit interest. In total, Longview has 34,155 gross (10,907 net) acres of Cardium rights in this area with Current Production of approximately 155 boe/d. This acreage is exclusive of a 1.5% working interest in the North Pembina Cardium Unit Number 1.

Pembina Rose Creek Cardium Unit

Longview has a 100% unit interest in and operates this 1,600 acre Cardium Formation unit which has Current Production of approximately 100 boe/d. The Cardium Formation in this unit consists of up to seven metres of net pay located within the southern boundary of the main Pembina field producing 36° API oil. The updip half of the property is overlain by one metre of highly permeable conglomerate. The unit has 15 active wells of which four are injecting water as pressure maintenance into the property. This property represents an opportunity for the application of multi-stage frac horizontal drilling in the Cardium trend.

The Sproule Report assigned 2.3 bcf of gross proved natural gas reserves and 2,051.8 Mbbls of gross proved crude oil and NGL reserves to the Westerose property. In addition, 1.1 bcf of gross probable natural gas reserves and 1,778.4 Mbbls of gross probable crude oil and NGL reserves have been assigned to this property.

Sunset, Alberta

This property consists of three pools all of which are producing from Triassic age Montney Formation reservoirs and lies approximately 100 kilometres east of the City of Grande Prairie. Current Production from the three main pools in the Sunset area is approximately 655 boe/d.

Sunset "A"

Current Production of 406 boe/d consists of 29º API crude oil from the Montney Formation occurring at 1,450 metres of depth. In this area, the Montney is a conventional tight fine grained sandstone reservoir in which crude oil has been trapped stratigraphically against cap rock overlying the updip subcrop unit of the reservoir. The reservoir has an underlying water leg which provides partial pressure support. Longview has a 70% working interest, and operates the Sunset Triassic "A" Unit. The field is currently developed with vertical wells drilled mainly on 40 acre spacing from central production pads. There is a 40 year production history with stable well performance and low decline. Infill drilling to 40 acre spacing in the pool commenced in 2005 and since that time 24 new oil wells and four additional injector wells have been added to the pool. In the center of the field, drilling has been successfully downspaced to 20 acre spacing units. A waterflood scheme was initiated in 2006 and expansion of the water injection system is ongoing. Once completed and re-pressurization of the reservoir has progressed sufficiently, further infill drilling will proceed to capture additional oil reserves.

Sunset "B"

Current Production from this Montney reservoir is approximately 219 boe/d of liquids rich natural gas. Longview has a 100% interest in this pool and owns 100% of a sour gas processing plant and gathering system with throughput capacity of 12 MMcf/d. Associated gas from Sunset "A" and from Valleyview is gathered and processed through this facility.

Valleyview

This Montney gas pool has Current Production of 127 boe/d and is connected to the Sunset "B" gas processing plant by a 12 kilometre pipeline with Longview holding a 93% average working interest in the pool.

The Sproule Report assigns 5.6 bcf of gross proved natural gas reserves and 1,012.1 Mbbls of gross proved crude oil and NGL reserves to Sunset/Valleyview. In addition, 10.5 bcf of gross probable natural gas reserves and 1,605.4 Mbbls of gross probable crude oil and NGL reserves have been assigned to these properties.

Duvernay and Nordegg Resource Play

The properties of Longview include a 100% interest in 78,750 gross (123 net sections) acres of exploratory rights in and along the Sunset corridor, which are prospective for development in the Upper Devonian Duvernay Formation shales as well as 15,719 net acres (61.4 net sections) for the Jurassic Nordegg Formation. A stratigraphic test well was drilled at the end of 2011 which cored both the Nordegg and Duvernay intervals. These cores are being analysed to further assess the potential of these lands for additional exploration. Longview believes that both the Duvernay and Nordegg lands are located within the oil generating window in this area and Longview will continue to review and analyze this target to determine future exploratory activity. Longview's ownership of oil and natural gas facilities in this area is available to provide immediate processing capacity should development proceed.

Skaro/Alexis, Alberta

Skaro, Alberta

The Skaro property is located 50 kilometres northeast of Edmonton, Alberta. This is an operated property in which Longview has a 100% working interest. Current Production at Skaro is approximately 136 boe/d. Oil is gathered and processed at 100% operated facilities where clean oil is then trucked out for sale. Production in this area is 17^{o} API gravity oil which occurs at shallow depths of 900 metres. Oil is trapped in pools within a large Cretaceous age, Ellerslie Formation, channel/valley trend in which numerous multi-well oil pools have accumulated. The pools are separated by shale filled channels which provide the hydrocarbon trap and separation of pools. On the Skaro lands there are two pools, the Basal Quartz (Ellerslie) "C" Pool which is currently developed with five horizontal wells and the Basal Quartz (Ellerslie) "G" Pool which has one producing horizontal well that was tied-in by pipeline during 2010.

The Sproule Report assigns to the Skaro area 255.0 Mbbls of gross proved crude oil and NGL reserves to this property. In addition, 106.4 Mbbls of gross probable crude oil and NGL reserves have been assigned to this property.

Alexis, Alberta

The Alexis property is located 50 kilometres northwest of Edmonton, Alberta. Longview holds a 13.966% non-operated working interest in the Alexis Banff "A" pool unit which produces slightly sour 22° API crude oil and natural gas from a siliclastic carbonate member within the Mississippian Banff Formation. There are 37 wells within the unit which is developed at 1,400 metres of depth with both vertical and horizontal producing wells and injection wells. Current Production at Alexis is 120 boe/d.

The Sproule Report assigns 1.1 bcf of gross proved natural gas reserves and 362.5 Mbbls of gross proved crude oil and NGL reserves to the Alexis property. In addition, 0.7 bcf of gross probable natural gas reserves and 168.5 Mbbls of gross probable crude oil and NGL reserves have been assigned to this property.

Saskatchewan

Southeast Saskatchewan

This area consists of a number of individual properties and lands located within the Williston Sedimentary Basin in the southeast quadrant of Saskatchewan. Existing production at the major properties comes principally from the Ordovician Red River Formation, Devonian Winnipegosis Formation as well as from the Mississippian Midale, Frobisher and Bakken Formations. Current Production from this area is approximately 1,927 boe/d and is comprised mainly of low decline, high netback, light oil with an average API gravity of 30°.

Weyburn and Steelman Area – Midale Formation Development

The Midale Formation is a Mississippian carbonate reservoir and contains one of Canada's largest light oil pools with API gravities ranging from 32° to 40°. The Midale Formation is comprised of two distinct fractured low permeability reservoirs which are the tight, high-porosity Marly zone that overlies the low-porosity Vuggy zone. The latter zone has higher permeability, and is more extensively fractured vertically than the Marly zone.

Longview has 68,017 gross undeveloped (55,628 net) acres of lands that are prospective for drilling in the Midale Formation and represents the largest opportunity base in the Southeast Saskatchewan area. Longview holds direct ownership of the mineral title in approximately 63% of the net acres.

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

Wapella Property

The Wapella property is located 200 kilometres east of Regina, Saskatchewan with Current Production of approximately 724 boe/d of 25º API gravity oil with an average working interest of 90%. Production is derived from the Cretaceous and Jurassic-age Shaunavon and Gravelbourg sandstone reservoirs located at a depth of 800 metres. Additional infill drilling and stepouts have been identified in and around the existing production from reservoirs.

Longview also has 18,793 gross (18,253 net) acres of undeveloped lands that are prospective in the Bakken Formation. Longview holds direct ownership of the mineral title in approximately 82% of the net acres. Significant exploration potential exists on the undeveloped land base and recent activity for Bakken target, to the east of Wapella, suggest that favourable geological potential in this horizon could extend westward onto lands to be acquired by Longview.

The Sproule Report assigns 2,568.1 Mbbls of gross proved crude oil and NGL reserves in Wapella. In addition, 1557.0 Mbbls of gross probable crude oil and NGL reserves have been assigned to this area.

Lloydminster, Saskatchewan Area

These properties lie east of the Saskatchewan/Alberta border within the Lloydminster heavy oil producing area. Current Production from these properties of approximately 528 boe/d is derived primarily from the Cretaceous Sparky and Waseca Formations and also from the Rex, Cummings and Dina Formations. Crude oil gravities in these properties average 20º API and are all being produced conventionally at this time.

Eyehill, Saskatchewan

The Eyehill property (100% working interest) consists of 24 oil wells with Current Production of approximately 293 boe/d producing from a 20º API Sparky Formation sand reservoir in which oil is trapped updip and laterally against shale filled channels. The Sparky oil pool is under waterflood pressure maintenance from six injection wells and is showing positive production response to this injection.

Lashburn, Saskatchewan

At Lashburn, in which Longview holds a 60% working interest, two thick Waseca channels are present as identified in vertical wells and on 3D seismic with Current Production of approximately 235 boe/d of 21º API oil. Similar Waseca channels are being developed immediately south of the property by a major oil company with SAGD (steam assisted gravity drainage) technology which could be utilized at the Lashburn property. As an alternative, this property may be developed through a combination of vertical and horizontal drilling to increase production and enhance reserves.

The Sproule Report assigns 1,442.9 Mbbls of gross proved crude oil and NGL reserves to the properties in the Lloydminster area. In addition, 2,719.7 Mbbls of gross probable crude oil and NGL reserves have been assigned to this area.

Oil and Gas Wells

The following table sets forth the number and status of wells as at December 31, 2011 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	612	298	176	83	1,545	895	267	158
Saskatchewan	268	216	186	160	74	5	9	4
Total(1)(2)	880	514	362	243	1,619	900	276	162

Note:

(1) Includes wells of Longview (without reduction to reflect the Longview Non-Controlling Interest).

Properties with no Attributed Reserves

The following table sets out our unproved properties as at December 31, 2011.

	Gross Acres	Net Acres
Alberta	374,193	184,044
Saskatchewan	119,178	83,547
Total(1)	493,371	267,591

Note:

(1) Includes developed and undeveloped land holdings of Longview (without reduction to reflect the Longview Non-Controlling Interest).

In the year ended December 31, 2011, rights to explore, develop and exploit 8,469 net acres of undeveloped land expired. We expect that rights to explore, develop and exploit 11,203 net acres of our undeveloped land holdings will expire by December 31, 2012. The land expirations do not consider our 2012 exploitation and development program that may result in extending or eliminating such potential expirations. We closely monitor land expirations as compared to our development program with the strategy of minimizing undeveloped land expirations relating to significant identified opportunities.

Forward Contracts

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

Advantage, including its subsidiary Longview, has approved a hedging policy using, amongst others, costless collars and fixed price swaps to hedge up to 60% of its gross oil, NGLs and natural gas production for a maximum period of three years. 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's subsidiary, Longview, has the following derivatives in place:

Description of Derivative	**Term**	**Volume**	**Average Price**
Crude Oil			
Fixed price	January 2012 to December 2012	1,000 bbls/d	Cdn $97.10/bbl
Collar	January 2012 to December 2012	1,000 bbls/d	Bought put Cdn $90.00/bbl Sold call Cdn $102.25/bbl
Electricity			
Fixed price	January 2012 to December 2012	0.9 MW	Cdn $77.88 MW/hr

Additional Information Concerning Abandonment and Reclamation Costs

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

We estimate that we will incur reclamation and abandonment costs on 1,819 net producing and non-producing wells and 716 net abandoned wells. The approximate net cost to abandon and reclaim all wells and facilities, discounted at 10%, totals $39.5 million ($310.6 million undiscounted), of which approximately $9.2 million are included in the estimate of future net revenue ($75.7 million undiscounted). Abandonment and reclamation costs undiscounted and expected to be paid over the next three years totals $12.3 million.

Tax Horizon

In 2011, we did not pay any income related taxes and it is expected, based on current legislation, that no cash income taxes are to be paid by AOG prior to 2017. 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, 2011:

Capital Expenditures ($ thousands)[(1)]	**2011**
Land and seismic	1,704
Drilling, completions and workovers	199,170
Well equipping and facilities	52,857
Other	443
Total expenditures on property, plant and equipment	254,174
Expenditures on exploration and evaluation assets	3,006
Property dispositions	(1,099)
Total capital expenditures	256,081

Note:

(1) Includes capital expenditures related to Longview (without reduction to reflect the Longview Non-Controlling Interest).

Exploration and Development Activities

The following table sets forth the gross and net wells in which we participated during the year ended December 31, 2011:

	Exploratory		**Development**		**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Oil wells	1.0	1.0	48.0	26.7	49.0	27.7
Gas wells	-	-	26.0	21.6	26.0	21.6
Service wells	-	-	-	-	-	-
Dry holes	-	-	-	-	-	-
Total[(1)]	1.0	1.0	74.0	48.3	75.0	49.3

Note:

(1) Includes wells in which Longview participated (without reduction to reflect the Longview Non-Controlling Interest).

Subject to, among other things, the availability of drilling rigs and weather that permits access to drill sites, in the first six months of 2012, we plan to drill, complete and tie-in 24 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, 2011 reflected in the estimate of future net revenue disclosed in the tables contained under "*Disclosure of Reserves Data*".

	Light and Medium Oil (bbls/d)		Heavy Oil (bbls/d)		Natural Gas (Mcf/d)		Natural Gas Liquids (bbls/d)		Total (Boe/d)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved Producing	3,828	3,278	582	506	119,137	109,533	1,386	1,048	25,652	23,087
Proved Developed Non-Producing	125	103	15	13	5,134	4,847	27	23	1,023	947
Proved Undeveloped	521	475	34	30	5,005	4,746	18	16	1,406	1,312
Total Proved	4,473	3,856	631	548	129,276	119,125	1,431	1,088	28,082	25,346
Total Probable	623	535	124	92	13,516	12,650	81	63	3,080	2,797
Total Proved Plus Probable(1)	5,096	4,390	754	640	142,793	131,773	1,512	1,151	31,161	28,143

Note:

(1) Includes Longview production (without reduction to reflect the Longview Non-Controlling Interest).

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 2011				Year Ended
	Mar. 31	June 30	Sept. 30	Dec. 31	Dec. 31, 2011
Average Daily Production					
Crude Oil (bbls/d)	4,537	4,459	4,658	5,182	4,711
Gas (Mcf/d)	111,145	136,986	134,353	137,480	130,075
NGLs (bbls/d)	1,714	1,460	1,588	1,316	1,519
Combined (boe/d)	24,775	28,750	28,638	29,411	27,909
Average Net Production Prices Received(2)					
Crude Oil ($/bbl)	81.34	94.99	82.31	89.34	87.02
Gas ($/Mcf)	3.72	3.77	3.62	3.18	3.55
NGLs ($/bbl)	59.71	67.73	59.69	78.09	65.64
Combined ($/boe)	35.71	36.16	33.69	34.11	34.88
Gain/(Loss) on Derivatives					
Crude Oil ($/bbl)	(3.58)	(2.73)	1.03	(1.48)	(1.65)
Gas ($/Mcf)	0.83	0.52	0.53	0.57	0.60
Combined ($/boe)	3.07	2.05	2.67	2.42	2.54
Royalties Paid					
Crude Oil ($/bbl)	13.71	19.70	18.44	20.24	18.11
Gas ($/Mcf)	0.32	0.30	0.22	0.12	0.24
NGLs ($/bbl)	16.80	22.51	19.95	17.79	19.21
Combined ($/boe)	5.12	5.62	5.13	4.93	5.20
Operating Expenses(3)(4)					
Crude oil ($/bbl)	19.08	19.27	21.11	18.48	19.46
Natural gas ($/Mcf)	1.26	1.01	.93	0.89	1.01
NGLs ($/bbl)	13.42	14.59	13.57	13.82	13.83
Combined ($/boe)	10.09	8.57	8.56	8.03	8.75

	Quarter Ended 2011				Year Ended
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**Dec. 31, 2011**
Netback Received[5]					
Crude Oil ($/bbl)	44.97	53.29	43.79	49.14	47.80
Gas ($/Mcf)	2.97	2.98	3.00	2.74	2.90
NGLs ($/bbl)	29.49	30.63	26.17	46.48	32.60
Combined ($/boe)	23.57	24.02	22.67	23.57	23.47

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 well by well basis based upon the relative volume of production of crude oil and NGLs and natural gas.
(4) Information in respect of netbacks received for crude oil & NGLs ($/bbl) and natural gas ($/Mcf) is calculated using operating expense figures for crude oil and NGLs ($/bbl) and natural gas ($/Mcf), which figures have been estimated. See note (4) above.
(5) Includes Longview (without reduction to reflect the Longview Non-Controlling Interest).

The following table indicates our approximate average daily production from our important fields for the quarter ended December 31, 2011:

Properties	Natural Gas (Mcf/d)	NGLs (bbls/d)	Crude Oil (bbls/d)	Total (boe/d)
Alberta				
Glacier	91,405	-	-	15,240
Nevis	5,634	412	869	2,219
Red Deer	9,160	98	65	1,689
Willesden Green	3,126	205	154	881
Lookout Butte	4,602	124	8	899
Medicine Hat	5,835	-	-	973
Westerose	2,564	190	422	1,039
Brazeau/Ferrier	2,958	111	78	682
Wainwright	2,685	-	5	452
North Eastern Alberta	1,643	-	-	274
Crossfield	1,622	123	80	474
Skaro/Alexis	186	-	225	256
Sunset	1,574	43	350	655
	132,994	1,306	2,256	25,733
Saskatchewan				
Southeast	121	2	1,905	1,927
Lloydminster	106	-	511	529
	227	2	2,416	2,456
Other	4,259	8	510	1,222
Total	137,480	1,316	5,182	29,411

Note:

(1) Includes Longview (without reduction to reflect the Longview Non-Controlling Interest).

Marketing

Our crude oil and natural gas production is primarily sold through marketing companies at current market prices. Crude oil contracts are generally for less than a year and are cancellable on 30 days notice and natural gas contracts are generally for one year and are cancellable on 60 days notice. NGL contracts are renegotiated annually and the contracts run for one year and are not cancellable for that term. Approximately 3.5% of our natural gas production is sold to aggregators who accumulate production from various producers and market the gas on behalf of the group. Such contracts are reserve specific and continue for the life of production from the specified reserves.

Cyclical and Seasonal Impact of Industry

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

Environmental Considerations

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

Health, Safety and Environmental

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

AOG's Health and Safety Management Program is recognized by Alberta Occupational Health and Safety, Alberta Workers Compensation Board and the Alberta Association of Safety Partnerships and as such AOG has received Certificates of Recognition from the above agencies.

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.

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.

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

Competitive Conditions

We are a member of the petroleum industry, which is highly competitive at all levels. We compete with other companies for all of our business inputs, including exploitation and development prospects, access to commodity markets, acquisition opportunities, available capital and staffing.

We strive to be competitive by maintaining a strong financial condition and by utilizing current technologies to enhance exploitation, development and operational activities.

DIRECTORS AND OFFICERS

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

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. Chief Operating Officer of Longview since December 15, 2010. President and Chief Operating Officer from June 23, 2006 to January 27, 2009. Prior thereto, President of Ketch Resources Ltd. since October 2005. Chief Operating Officer of Ketch Resources Ltd. from January 2005 to September 2005. Prior thereto, Executive Officer and Vice President, Engineering and Operations of Northrock Resources Ltd. from August 1998 to January 2005.
Kelly I. Drader Alberta, Canada	Chief Financial Officer since January 27, 2009 and Director since May 24, 2001	Chief Financial Officer of AOG since January 27, 2009. President of AOG from January 27, 2009 to April 21, 2011. President and Chief Executive Officer of Longview since December 15, 2010. Chief Executive Officer of AOG from May 24, 2001 to January 27, 2009. President of AIM from March 2001 to June 2006. Prior thereto, Senior Vice President (1997-2001) and Vice President, Finance and Chief Financial Officer (1990-1997) of EnerPlus Group of Companies, which companies specialize in the management of oil and gas income funds and royalty trusts.
John A. Howard (2)(3)(7) Alberta, Canada	Director since June 23, 2006	Mr. Howard is currently a private investor and company director in the Canadian oil and gas sector. He is a Professional Engineer who has had an active career spanning 40 years, including 20 years as a President and CEO of: Barrington Petroleum Ltd., Seagull Energy Canada Ltd., Novalta Resources Ltd and Aberford Resources Corp. Since 2000, Mr. Howard has been a Board member of seven reporting issuers including: Advantage /Advantage Energy Income Fund/Ketch Resources Trust; Rockyview Energy Inc.(Chairman)/APF Energy Trust; and Bear Ridge Resources Inc./Bear Creek Energy Ltd. Also since the year 2000, he has been an investor in and director of 10 widely held private non-reporting issuers.
Ronald A. McIntosh(1)(3)(8) Alberta, Canada	Director since September 25, 1998(6)	Chairman of North American Energy Partners Inc., a publicly traded corporation and a director of Fortress Energy Inc. 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)(3) Alberta, Canada	Director since August 16, 2007	President, West Butte Management Inc. and Principal of Alconsult International Ltd., both of which are 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.
Carol D. Pennycook(1)(2) Ontario, Canada	Director since May 26, 2004	Partner at the Toronto office of Davies Ward Phillips & Vineberg, LLP, a national law firm.
Steven Sharpe Ontario, Canada	Director since May 24, 2001 and Non-Executive Chairman since May 26, 2004	Managing Director, The EmBeSa Corporation. Mr. Sharpe is, and has been, a director of Longview since April 27, 2010. Until January, 2012, he was also Chairman of Prime Restaurants Inc. Since December, 2011, he is also a director of C.A. Bancorp. Inc. From October 2009 to March 2010, Mr. Sharpe was Chairman and Chief Executive Officer of Prime Restaurants Royalty Income Fund. Until July, 2009, he was Senior Advisor to Blair Franklin Capital Partners, Inc., a Toronto-based investment bank which he co-founded in May, 2003. Prior to that, Mr. Sharpe was Managing Partner of Blair Franklin, from its inception. Before then, he was Managing Director of The EBS Corporation, a management and strategic consulting firm. Prior to EBS, Mr. Sharpe was Executive Vice President of The Kroll-O'Gara Company ("**Kroll**"), New York. Prior to his joining Kroll, Mr. Sharpe was a senior partner with Davies, Ward & Beck in Toronto.

Name, Province and Country of Residence	Position Held and Period Served as a Director or Officer(4)(5)	Principal Occupations During Past Five Years
Sheila O'Brien(2) (3) Alberta, Canada	Director since March 21, 2007	Ms. O'Brien has over 35 year's experience in the oil and gas, pipeline and petrochemicals sector, in Canada the USA, Europe and South America. She has held leadership positions in human resources, public affairs, health safety and the environment, and government and investor relations. In her roles as a senior executive with NOVA corporation, she led the team that designed an innovative workplace restructuring program that was designated a Worldwide Best Practice by Watson Wyatt consultancy. Ms. O'Brien is the author of two books, "An Extraordinary West" and "Catching a Rising Tide – an energy vision for Canada" published by the Canada West Foundation. She was inducted in the Order of Canada in 1998, and received the Jubilee Medal for public service in 2012.
Paul Haggis (1) Alberta, Canada	Director since November 7, 2008	Mr. Haggis' was President and Chief Executive Officer of Ontario Municipal Employees Retirement System (OMERS) from September 2003 to March 2007, Interim Chief Executive Officer of the Public Sector Pension Investment Board (PSPIB) during 2003 and Executive Vice-President, Development and Chief Credit Officer of Manulife Financial in 2002. Mr. Haggis has extensive financial markets and public board experience and currently serves on the Board of Directors of Canadian Tire Bank and as a director and Chair of the Investment Committee of the Insurance Corporation of British Columbia. He is also Chair of the Audit Committee of C.A. Bancorp and Prime Restaurants Royalty Income Fund. He is in addition a member of the Board of UBC Investment Management Inc. and a Chairman of Alberta Enterprise Corp.
Patrick J. Cairns Alberta, Canada	Senior Vice President	Senior Vice President of AOG since June 2001. Senior Vice President of Longview since May 13, 2011. Prior thereto, Mr. Cairns was Vice President, Evaluations with the Enerplus Group of Companies, which companies specialize in the management of oil and gas income funds and royalty trusts.
Craig Blackwood Alberta, Canada	Vice President, Finance	Vice President, Finance of AOG since January 27, 2009. Chief Financial Officer of Longview since March 4, 2010. Mr. Blackwood is a Chartered Accountant and was the Director of Finance of AOG from November 2004 to January 27, 2009.
Neil Bokenfohr Alberta, Canada	Vice President, Exploitation	Vice-President, Exploitation of AOG since June 23, 2006. Vice-President, Exploitation of Longview since May 13, 2011. Prior thereto, Vice President Exploitation and Operations of Ketch Resources Ltd. since January 2005; Vice President, Engineering of Bear Creek Energy Ltd. (and Crossfield Gas Corp. prior thereto) from March 2002 to January 2005. Prior thereto, Director of Exploitation for Calpine Canada Natural Gas Company from December 2000 to March 2002.
Weldon M. Kary Alberta, Canada	Vice President, Geosciences and Land	Vice President, Geosciences and Land of AOG since February 14, 2005. Vice President, Geosciences and Land of Longview since May 13, 2011. Prior thereto, Manager, Geology and Geophysics with AOG since May 23, 2001. Prior thereto, Exploration Manager at Palliser Energy Corp. when Palliser was purchased by Search Energy Corp, the predecessor entity of AOG.
Jay P. Reid Alberta, Canada	Corporate Secretary	Partner 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 a Director of Madalena Ventures Inc. and Renegade Petroleum Ltd. and as Corporate Secretary for Pinecrest Energy Inc., TriOil Resources Ltd. and Longview Oil Corp. in addition to being a Director or Corporate Secretary for six private issuers.

Notes:

(1) Member of the Audit Committee.
(2) Member of the Human Resources, Compensation and Corporate Governance Committee.
(3) Member of the Reserve Evaluation Committee.
(4) AOG does not have an executive committee of the Board.
(5) AOG's directors shall hold office until the next annual general meeting of Shareholders or until each director's successor is appointed or elected pursuant to the ABCA.
(6) The period of time served by Ronald A. McIntosh as a director of AOG includes the period of time served as a director of Search prior to the Amalgamation, where applicable. Mr. McIntosh was appointed a director of post-Reorganization Search on May 24, 2001.
(7) Mr. Howard was the President, Chief Executive Officer and Director of Sunoma Energy Corp. Immediately upon his resignation from the executive and board of directors, Sunoma Energy Corp. filed for Court protection.
(8) Mr. McIntosh is 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.

As at March 23, 2012 the directors and executive officers of AOG, as a group, beneficially owned, directly or indirectly, or exercised control or direction over, 1,944,707 Common Shares, or approximately 1.2% 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.

Certain officers and directors of the Corporation also form part of the management of Longview including Kelly Drader, the President and Chief Executive Officer of Longview, Craig Blackwood, the Chief Financial Officer of Longview, Andy Mah, the Chief Operating Officer of Longview, Patrick Cairns, the Senior Vice President of Longview, Neil Bokenfohr, the Vice President, Exploitation of Longview, Weldon Kary, the Vice President, Geosciences and Land of Longview, Jay P. Reid, the Corporate Secretary of Longview, and Steven Sharpe, a director of each of the Corporation and Longview. As a result, there is the potential for these individuals to encounter conflicts of interests in the event that the interests of the Corporation and Longview diverge. See also "*Interest of Management and Others in Material Transactions*".

DIVIDEND POLICY

Dividend Policy of the Corporation

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

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

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

Note:

(1) On March 18, 2009 we announced that monthly distributions had been suspended with the final cash distribution paid to Unitholders on March 16, 2009 to Unitholders of record as of February 27, 2009. See "*General Development of the Business*". We have not paid any dividends or distributions on the Common Shares.

Dividend Policy of Longview

Longview has established a policy of declaring regular monthly cash dividends since the completion of the Longview Offering and the Longview Transaction. The payment and the amount of dividends declared in any month is subject to the discretion of the board of directors of Longview and will depend on the board of director's assessment of Longview's outlook for growth, capital expenditure requirements, funds from operations, potential acquisition opportunities, debt position and other conditions that the board of directors of Longview may consider relevant at such future time, including applicable restrictions that may be imposed under Longview's credit facilities and on the ability of Longview to pay dividends upon the satisfaction of the liquidity and solvency tests imposed by the ABCA for the declaration and payment of dividends. The amount of future cash dividends, if any, may also vary depending on a variety of factors, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens and foreign exchange rates.

The following is a summary of the dividends declared and paid by Longview for the most recently completed financial year.

For the 2011 Period Ended	Dividend per Common Share	Payment Date
May 31	$ 0.05	June 15, 2011
June 30	$ 0.05	July 15, 2011
July 31	$ 0.05	August 15, 2011
August 31	$ 0.05	September 15, 2011
September 30	$ 0.05	October 17, 2011
October 31	$ 0.05	November 17, 2011
November 30	$ 0.05	December 15, 2011
December 31	$ 0.05	January 16, 2012
Total:	$ 0.40	

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, 2011, there were 166,304,040 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

The 5.00% Debentures pay interest semi-annually and are 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, 2011 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

The 5.00% Debentures are redeemable prior to their maturity date, at the option of the Corporation, upon providing appropriate days advance notification as per the terms of the debenture indenture. The redemption price for the 5.00% Debentures is $1,000, plus accrued and unpaid interest, and are redeemable after January 31, 2013 and on or before January 30, 2015, provided that the Current Market Price of the Common Shares exceeds 125% of conversion price noted above.

PRICE RANGE AND TRADING VOLUME OF SECURITIES

Common Shares

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

Period	High	Low	Volume
	($)	($)	
TSX Trading			
2011			
January	7.47	6.61	13,034,855
February	7.83	7.33	7,466,185
March	9.00	7.40	18,472,197
April	8.90	7.84	11,937,306
May	8.17	7.33	9,202,264
June	8.51	7.35	18,224,659
July	7.85	6.59	9,796,515
August	6.82	5.10	18,220,615
September	5.76	3.82	11,980,690
October	5.49	3.79	24,283,919
November	5.57	4.43	18,018,795
December	4.92	3.82	15,063,224
2012			
January	4.46	3.35	21,564,836
February	4.15	3.51	21,267,458
March (1 to 22)	3.93	3.53	15,576,426
NYSE Trading (U.S.$)			
2011			
January	7.45	6.65	3,432,750
February	7.94	7.38	2,807,182
March	9.22	7.49	6,677,307
April	9.29	8.14	3,266,936
May	8.56	7.57	3,055,715
June	8.68	7.53	2,929,906
July	8.17	6.90	2,300,788
August	7.19	5.15	5,583,037
September	5.90	3.83	3,216,220
October	5.52	3.57	4,242,971
November	5.50	4.22	2,798,687
December	4.86	3.68	2,819,422
2012			
January	4.39	3.32	3,369,607
February	4.17	3.52	2,573,324
March (1 to 22)	3.98	3.56	2,611,994

5.00% Debentures

The 5.00% Debentures are listed for trading on the TSX under the symbol "AAV.DB.H". The following table sets forth the high and low trading prices and the aggregate trading volume of the 5.00% Debentures as reported by the TSX for the period indicated.

Period	High ($)	Low ($)	Volume
2011			
January	108.00	104.00	81,730
February	112.00	108.44	27,440
March	121.00	109.50	44,290
April	120.00	109.00	11,970
May	115.00	111.00	27,560
June	115.00	109.24	3,810
July	115.90	104.69	131,440
August	104.13	97.00	51,970
September	99.00	89.51	28,870
October	96.99	89.00	21,660
November	97.00	92.68	60,610
December	97.00	93.75	25,780
2012			
January	98.99	95.00	161,300
February	98.00	97.00	23,550
March (1 to 22)	98.10	97.02	32,800

Prior Sales

During the year ended December 31, 2011, the Corporation granted an aggregate of 1,443,956 restricted shares with a weighted average price of $7.78.

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, 2011, which involved claims in excess of 10% of the Corporation's current asset value 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, 2011 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, 2011 or in any proposed transaction which has materially affected or would materially affect AOG or its subsidiaries.

Steven Sharpe, a director of AOG, is a director of Longview. In addition, concurrent with closing of the Longview Offering, AOG entered into the TSA pursuant to which AOG provides the necessary personnel and technical services to manage Longview's business. The officers of Longview are Kelly Drader (President and Chief Executive Officer), Craig Blackwood (Chief Financial Officer), Andy Mah (Chief Operating Officer), Patrick Cairns (Senior

Vice President), Neil Bokenfohr (Vice President, Exploitation) and Weldon Kary (Vice President, Geosciences and Land), each of which are executive officers of AOG. The officers of Longview provide services to Longview under the TSA but will remain as employees of Advantage. See "*General Development of the Business – 2011*".

MATERIAL CONTRACTS

Material Contracts of AOG

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.

Material Contracts of Longview

Except for contracts entered into in the ordinary course of business the only agreements which are material to Longview are the agreement for the Longview credit facility, the TSA, the governance agreement between AOG and Longview (the "**Governance Agreement**") and the registration rights agreement between AOG and Longview (the "**Registration Rights Agreement**"), copies of which agreement are available on Longview's SEDAR profile at www.sedar.com and the terms of which are summarized below.

Longview Credit Facilities

In connection with the Longview Transaction, on April 14, 2011, Longview entered into a credit agreement with a syndicate of financial lenders for an extendible revolving credit facility in the maximum principal amount of $180 million as well as an operating credit agreement with a Canadian financial institution in the maximum principal amount of $20 million. The Longview Credit Facilities are collateralized by a floating charge demand debenture of $1 billion over Longview's assets. Various borrowing options are available under the Longview Credit Facilities, including prime rate loans, bankers' acceptances, U.S. base rate loans and LIBOR loans. The amounts available to Longview from time to time under the Longview Credit Facilities are based upon the borrowing base determined by the financial lenders which is re-determined by the lenders on an annual basis after the receipt of the independent engineering report and such other information as required by the lenders. The next redetermination of the borrowing base is anticipated to occur in April of 2012. The borrowing base constitutes a revolving facility for a 364 day term which is extendible for a further 364 day revolving period, at the option of the lenders.

Technical Services Agreement

Longview entered into the Technical Services Agreement with Advantage on April 14, 2011. Under the Technical Services Agreement, Advantage provides the necessary personnel and technical services to manage Longview's business and Longview reimburses Advantage on a monthly basis for its share of administration charges equal to: (i) its proportionate share of Advantage's general and administrative costs, based upon its level of oil and natural gas production relative to the combined level of oil and natural gas production for Advantage and Longview but such general and administrative costs do not include direct costs attributable to Advantage, including, but not limited to, fees payable to the board of directors of Advantage, and fees associated with Advantage being a public company (including, but not limited to, expenses associated with ongoing financial reporting and disclosure, listing fees, legal fees, audit fees, director fees and costs related to ongoing investor relations and annual meetings); plus (ii) direct general and administrative costs for engineering, acquisition, legal and other professional services; less (iii) operating and capital overhead recoveries directly attributable to the Acquired Assets. As of December 31, 2011, Longview has paid $3.8 million pursuant to the Technical Services Agreement.

The Technical Services Agreement became effective upon the completion of the Acquisition of the Acquired Assets and will continue for an initial period of one year, ending on April 14, 2012. The term of the Technical Services Agreement will automatically renew for an additional one year term on each anniversary date of the agreement. Following the first year of the operation of the Technical Services Agreement, either party may terminate the Technical Services Agreement by providing 120 days written notice to the other party.

Registration Rights Agreement

Longview entered into the Registration Rights Agreement with Advantage on April 14, 2011. The Registration Rights Agreement provides that for a period commencing 12 months after the date a receipt has been issued for the final prospectus under applicable securities legislation in Canada for the Offering (April 6, 2011) and expiring on the earlier of: (i) a date that is seven years from the date of the Registration Rights Agreement; or (ii) the date that is three months after the date that Advantage ceases to be the beneficial holder of more than 10% of the outstanding common shares of Longview, Advantage may require Longview to prepare, file and obtain a receipt for a final prospectus under applicable securities legislation in Canada qualifying the distribution of some or all of the common shares or other securities of Longview held by Advantage. Such right is subject to certain restrictions. In addition, during the aforementioned period, Advantage has the right to receive prompt notice should Longview propose to file a prospectus in Canada pursuant to an offering of Longview's securities and Advantage may include some or all of the common shares or other securities of Longview held by Advantage for distribution pursuant to the said offering. Such right is subject to certain restrictions.

Governance Agreement

The Governance Agreement was also entered into on April 14, 2011 pursuant to which Advantage agreed that until the earlier of: (i) the date that Advantage ceases to be the beneficial owner of more than 50% of the outstanding common shares of Longview; and (ii) the date that Advantage and Longview otherwise agree to in writing, Advantage will vote its common shares of Longview in such a manner so as to ensure that the board of directors of Longview is comprised of a majority of independent directors. Pursuant to the Governance Agreement, Longview will agree to include in any slate or individual list of directors proposed for election at a meeting of shareholders such independent directors as may be nominated or put forward by Advantage. Advantage's agreement to vote its common shares of Longview to ensure that the majority of the directors of Longview are independent, will not apply in the circumstances where a dissident slate or list of directors is being proposed by a third party.

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 relevant legislation and requirements of the Public Company Accounting Oversight Board (PCAOB).

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of AOG or of any associate or affiliate of AOG except for Mr. Jay Reid, the Corporate Secretary of AOG, who is a partner of Burnet, Duckworth & Palmer LLP, which law firm provides AOG with legal services.

AUDITORS, TRANSFER AGENT AND REGISTRAR

Our auditors are PricewaterhouseCoopers LLP, Chartered Accountants, Calgary, Alberta.

Computershare Trust Company of Canada at its offices in Calgary, Alberta and Toronto, Ontario acts as the transfer agent and registrar for the Common Shares and the 5.00% Debentures.

AUDIT COMMITTEE INFORMATION

Composition of the Audit Committee

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

Name, Province and Country of Residence	Independent	Financially Literate	Relevant Education and Experience
Ronald A. McIntosh Alberta, Canada	Yes	Yes	Mr. McIntosh is the Chairman and member of audit committee of North American Energy Partners Inc., a publicly traded corporation. Mr. McIntosh was also the Chairman and a member of the audit committee of Tasman Exploration Ltd., a private oil and gas company. He is also a director of Fortress Energy Inc.
Paul Haggis Alberta, Canada	Yes	Yes	Mr. Haggis' was President and Chief Executive Officer of Ontario Municipal Employees Retirement System (OMERS) from September 2003 to March 2007, Interim Chief Executive Officer of the Public Sector Pension Investment Board (PSPIB) during 2003 and Executive Vice-President, Development and Chief Credit Officer of Manulife Financial in 2002. Mr. Haggis has extensive financial markets and public board experience and currently serves on the Board of Directors of Canadian Tire Bank and as a director and Chair of the Investment Committee of the Insurance Corporation of British Columbia. He is also Chair of the Audit Committee of C.A. Bancorp and Prime Restaurants Royalty Income Fund, a member of the Board of UBC Investment Management Inc. and a Chairman of Alberta Enterprise Corp. Mr. Haggis holds a Bachelor of Arts degree from the University of Western Ontario and is certified as a Chartered Director through the Directors College at McMaster University.
Stephen Balog Alberta, Canada	Yes	Yes	Mr. Balog is President of West Butte Management Inc. and a Principal of Alconsult International Ltd., both of which are private consulting companies that provide technical and business advisory services to oil and gas operators. Prior thereto, Mr. Balog was President and Chief Operating Officer and a director of Tasman Exploration Ltd. from 2001 to June,2007, and was a director of BelAir Energy Corporation, a junior public company. He served on the Petroleum Advisory Committee, Alberta Securities Commission from 2009-2011 and has a Bachelor of Science, Chemical Engineering.
Carol D. Pennycook Ontario, Canada	Yes	Yes	Ms. Pennycook is a partner at the Toronto offices of Davies Ward Phillips & Vineberg, LLP, a national law firm. Ms. Pennycook received her LLB in 1979 and has been a partner since 1986. A significant portion of Ms. Pennycook's practice involves financing transactions.

Pre-Approval of Policies and Procedures

We have adopted 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	2010	2011
Audit Fees	$ 645,000	$ 486,000
Audit-Related Fees	251,350[1]	40,000
Tax Fees (these services included general tax consultations)	-	-

Note:

(1) Includes work related to prospectus for the Longview Transaction.

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government and with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta and Saskatchewan, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these regulations or controls will affect the Corporation's operations in a manner materially different than they will affect other oil and natural gas companies of similar size. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in western Canada.

Pricing and Marketing

Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, 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.

Natural Gas

The price of the vast majority of natural gas produced in western Canada is now determined through highly liquid market hubs such as the Alberta "NIT" (Nova Inventory Transfer) hub rather than through direct negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m3/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 governments of Alberta and Saskatchewan also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico became effective on January 1, 1994. 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.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of 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, from time to time, carved out of the working interest owner's interest through non public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

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

Alberta

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

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. Effective January 1, 2011, the maximum royalty payable under the royalty regime was set at 40%. The royalty curve for conventional oil announced on May 27, 2010 amends the price component of the conventional oil royalty formula to moderate the increase in the royalty rate at prices higher than $535/m3 compared to the previous royalty curve.

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

Oil sands projects are also subject to the 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 and Cushing, Oklahoma: rates are 1% when the market price of oil is less than or equal to $55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of 1-9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above $55 up to 40% when oil is priced at $120 or higher. In addition, concurrently 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 current royalty regime.

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

The Innovative Energy Technologies Program (the "**IETP**"), which is currently in place, 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.

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

On November 19, 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The five-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well's life when production rates are expected to be the highest. Under this program, companies drilling new natural gas or conventional deep oil wells (between 1,000 and 3,500 m) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the royalty regime. These options expired on February 15, 2011 and on January 1, 2014, all producers operating under the transitional royalty rates will automatically become subject to the royalty regime. The revised royalty curves for conventional oil and natural gas will not be applied to production from wells operating under the transitional royalty rates.

On March 3, 2009, the Government of Alberta announced a three-point incentive program in order to stimulate new and continued economic activity in Alberta. One aspect of the program was a drilling royalty credit program which provided up to a $200 per metre royalty credit for new wells. The drilling credit program applied to wells that were drilled between April 1, 2009 and March 31, 2010 and has not been extended for wells drilled after March 31, 2010. Another aspect of the program was a new well royalty program which provided for a maximum 5% royalty rate for eligible new wells for the first twelve (12) productive months or until the regulated "volume cap" was reached. The *New Well Royalty Regulation*, providing for the permanent implementation of this incentive program, was approved by an Order-in-Council on March 17, 2011.

In addition to the foregoing, 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 on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;
- Shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;
- Horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; 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.

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

Saskatchewan

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

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil. Where average wellhead prices are below the established base prices of $100 per m3 for third and fourth tier oil and $50 per m3 for new oil and old oil, base royalty rates are applied. Base royalty rates are 5% for all fourth tier oil, 10% for heavy oil that is third tier oil or new oil, 12.5% for southwest designated oil that is third tier oil or new oil, 15% for non heavy oil other than southwest designated oil that is third tier or new oil, and 20% for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30% for all fourth tier oil, 25% for heavy oil that is third tier oil or new oil, 35% for southwest designated oil that is third tier oil or new oil, 35% for non heavy oil other than southwest designated oil that is third tier or new oil, and 45% for old oil.

The amount payable as Crown royalty or freehold production tax in respect of natural gas production is determined by a sliding scale based on the actual price received, the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. Like conventional oil, natural gas may be classified as "non-associated gas" or "associated gas" and royalty rates are determined according to the finished drilling date of the respective well. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on natural gas produced in association with oil is less than on non associated natural gas. Non-associated gas is classified as new gas (having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of more than 3,500 m3 of gas for every m3 of oil, and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties.

On December 9, 2010, the Government of Saskatchewan enacted the *Freehold Oil and Gas Production Tax Act, 2010* replacing the existing *Freehold Oil and Gas Production Tax Act* with the intention to facilitate more efficient payment of freehold production taxes by industry. No regulations have been passed with respect to the calculation of freehold production taxes under the new legislation, although several regulations remain in force under the previous legislation.

As with conventional oil production, base prices are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of $50 per thousand m3 for third and fourth tier gas and $35 per thousand m3 for new gas and old gas, base royalty rates are applied. Base royalty rates are 5% for all fourth tier gas, 15% for third tier or new gas, and 20% for old gas. Where average well-head prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30% for all fourth tier gas, 35% for third tier and new gas, and 45% for old gas.

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

- *Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 8,000 m3 for deep development vertical oil wells, 4,000 m3 for non-deep exploratory vertical oil wells and 16,000 m3 for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations);

- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 m3 for qualifying exploratory gas wells;

- *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 6,000 m3 for non-deep horizontal oil wells and 16,000 m3 for deep horizontal oil wells (more than 1,700 metres or within certain formations);

- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013* providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 m3 for horizontal gas wells;

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

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

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

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

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

On June 22, 2011, the Government of Saskatchewan released the Upstream Petroleum Industry Associated Gas Conservation Standards which are designed to reduce emissions resulting for the flaring and venting of associated gas (the "**Associated Natural Gas Standards**"). The Associated Natural Gas Standards were jointly developed with industry and the implementation of such standards is set to commence on July 1, 2012 for new wells and facilities licensed on or after such date, and to apply to existing licensed wells and facilities on July 1, 2015.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

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

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. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. Leases and licences that were granted prior to January 1, 2009 but continued after that date are not subject to shallow rights reversion until they reach the end of their primary term and are continued (at which time deep rights reversion will be applied); thereafter, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009. The order in which these agreements will receive reversion notices will depend on their vintage and location, and the Government of Alberta had anticipated that the receipt of reversion notices for older leases and licenses would commence in April 2011. However, on April 14, 2011, the Government of Alberta announced it was deferring serving shallow rights reversion notices and will revisit the decision in spring 2012.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

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

The *Alberta Land Stewardship Act* (the "**ALSA**") was proclaimed in force in Alberta on October 1, 2009 and provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA will be 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, leases, licenses, 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 29, 2011 the Government of Alberta released a revised draft of the Lower Athabasca Regional Plan (the "**Revised LARP**") updating its prior draft of April 5, 2011 (the "**Draft LARP**"). The Revised LARP, while establishing several conservation areas of the Athabasca region, has changed the boundaries of certain conservation areas outlined in the Draft LARP with the result that fewer oil sands leases appear to be impacted. Consistent with the Draft LARP, as the intention of the Revised LARP is to manage the areas to minimize or prevent new land disturbance, activities associated with oil sands development are considered incompatible with the intent to manage such conservation areas. However, references to the cancellation of existing tenures have been removed from the Revised LARP and the Revised LARP now contemplates that the conservation areas will be created pursuant to existing legislation rather than the previously contemplated regulations. Existing conventional petroleum and natural gas rights will not be affected, although the Revised LARP raises some question as to whether new conventional leases and licenses will be granted in the conservation areas in the future. The planning process is also underway for a regional plan for the South Saskatchewan Region.

Climate Change Regulation

Federal

In December 2002, the Government of Canada ratified the Kyoto Protocol ("**Kyoto Protocol**"), which requires a reduction in greenhouse gas ("**GHG**") emissions by signatory countries between 2008 and 2012. The Kyoto Protocol officially came into force on February 16, 2005 although on December 12, 2011 Canada formally withdrew from the Kyoto Protocol.

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

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

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

Four separate compliance mechanisms are provided for in the Updated Action Plan in respect of the above targets:

(a) Regulated entities will be able to use Technology Fund contributions to meet their emissions intensity targets. The contribution rate for Technology Fund contributions will increase over time, beginning at $15 per tonne of CO_2 equivalent for the 2010 to 2012 period, rising to $20 in 2013, and thereafter increasing at the nominal rate of GDP growth. Maximum contribution limits will also decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce GHG emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as described above.

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

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

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

From December 7 to 18, 2009, government leaders and representatives met in Copenhagen, Denmark and agreed to the Copenhagen Accord, which reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. Another meeting of government leaders and representatives in 2010 resulted in the Cancun Agreements wherein developed countries committed to additional measures to help developing countries deal with climate change. Neither the Copenhagen Accord nor the Cancun Agreements establish binding GHG emissions reduction targets. In response to the Copenhagen Accord, the Government of Canada indicated that it will seek to achieve a 17% reduction in GHG emissions from 2005 levels by 2020.

Although draft regulations for the implementation of the Updated Action Plan were intended to become binding on January 1, 2010, only draft regulations pertaining to carbon dioxide emissions from coal-fired generation of electricity have been proposed to date. Further, 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. As a result, it is unclear to what extent, if any; the proposals contained in the Updated Action Plan will be implemented.

The United States Environmental Protection Agency (the "**EPA**") has indicated its intention to impose GHG emissions standards for fossil fuel-fired power plants by specifying that it will issue final regulations by May 26, 2012, and with respect to refineries, specifying that it will issue proposed regulations by December 10, 2011 and finalized regulations by November 10, 2012. The EPA did not meet the December 10, 2011 deadline and it is unclear whether the EPA will also miss the finalized regulations deadline.

Alberta

Alberta enacted the *Climate Change and Emissions Management Act* (the "**CCEMA**") on December 4, 2003, amending it through the *Climate Change and Emissions Management Amendment Act* which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach similar to the Updated Action Plan and aims for a 50% reduction from 1990 emissions relative to GDP by 2020.

Alberta facilities emitting more than 100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. Similar to the Updated Action Plan, the CCEMA and the associated *Specified Gas Emitters Regulation* make a distinction between "Established Facilities" and "New Facilities". Established Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2000 or that have completed eight or more years of commercial operation. Established Facilities are required to reduce their emissions intensity to 88% of their baseline for 2008 and subsequent years, with their baseline being established by the average of the ratio of the total annual emissions to production for the years 2003 to 2005. New Facilities are defined as facilities that completed their first year of commercial operation on December 31, 2000, or a subsequent year, and have completed less than eight years of commercial operation, or are designated as New Facilities in accordance with the *Specified Gas Emitters Regulation*. New Facilities are required to reduce their emissions intensity by 2% from baseline in the fourth year of commercial operation, 4% of baseline in the fifth year, 6% of baseline in the sixth year, 8% of baseline in the seventh year, and 10% of baseline in the eighth year. Unlike the Updated Action Plan, the CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA contains compliance mechanisms that are similar to the Updated Action Plan. Regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund (the "**Fund**") at a rate of $15 per tonne of CO2 equivalent. Unlike the Updated Action Plan, CCEMA contains no provisions for an increase to this contribution rate. Emissions credits can be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta.

On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010,* which deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

Advantage does not have a working interest in any facility that is expected to exceed emissions thresholds.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. The MRGGA received Royal Assent on May 20, 2010 and will come into force on proclamation. Regulations under the MRGGA have also yet to be proclaimed, but draft versions indicate that Saskatchewan will adopt the goal of a 20% reduction in GHG emissions from 2006 levels by 2020 and permit the use of pre-certified investment credits, early action credits and emissions offsets in compliance, similar to both the federal and Alberta climate change initiatives. It remains unclear whether the scheme implemented by the MRGGA will be based on emissions intensity or an absolute cap on emissions.

RISK FACTORS

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

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

Prices, Markets and Marketing

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

The prices of oil and natural gas prices may be volatile and subject to fluctuation. Any material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or 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 of 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. 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 of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and 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 as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions, and sanctions imposed on certain oil producing nations by other countries and the ongoing credit and liquidity concerns. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

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

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Corporation may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Corporation's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Corporation will be able to continue to locate satisfactory properties for acquisition or participation therein. Moreover, if such acquisitions or participations are identified, management of the Corporation may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Corporation.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, 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 or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including fire, explosion, blowouts, cratering, sour gas releases, spills or other environmental hazards, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, the Corporation may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation. 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. In accordance with 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, the nature of certain risks is such that liabilities could exceed policy limits or not be covered, in either event the Corporation could incur significant costs.

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 herein are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and 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 oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times may vary. The

Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

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

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

Actual production and cash flows derived from the Corporation's oil and 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 contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and has not been updated and thus does not reflect changes in the Corporation's reserves since that date.

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.

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 within 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;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Corporation could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

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. Also, 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 declines in the demand for the goods and services of the Corporation.

Gathering and Processing Facilities and Pipeline Systems

The Corporation delivers its products through gathering, processing 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, processing and pipeline systems. The lack of availability of capacity in any of the gathering, processing and pipeline systems, 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. 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.

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 materially adversely affect the Corporation's ability to process its production and to deliver the same for sale.

Competition

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

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 therewith the Corporation's access to capital could be restricted or repayment could be required. The failure of the Corporation to comply with such covenants, which may be affected by events beyond the Corporation's control, 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, 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, from time to time, 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, 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 borrowing base is determined and re-determined by the Corporation's lenders based on the Corporation's reserves, commodity prices, applicable discount rate and other factors as determined by the Corporation's lenders. A material decline in commodity prices could reduce the Corporation's borrowing base, therefore reducing the funds available to the Corporation under the credit facility which could result in a portion, or all, of the Corporation's bank indebtedness be required to be repaid.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate hydrocarbon (oil and natural gas) production. The use of hydraulic fracturing is being used to produce 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 or 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.

Global Financial Crisis

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 conditions have caused a decrease in confidence in the 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. This volatility may in the future affect the Corporation's ability to obtain equity or debt financing on acceptable terms.

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;
- 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 in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, the Corporation will not benefit from the fluctuating exchange rate.

Variations in Foreign Exchange Rates and Interest Rates

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

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

An increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt, which could negatively impact the market price of the Common Shares.

Environmental

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

Regulatory

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

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 impact a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

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 2017. 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. As a result, the Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others therefore depends upon a number of factors that may be outside of the Corporation's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Corporation's claim which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. There may be valid challenges to title, or proposed legislative changes which affect title, to the oil and natural gas properties the Corporation controls that, if successful or made into law, 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 in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired businesses may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non core assets may be periodically disposed of, so that the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such non core assets, certain non core assets of the Corporation, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Corporation.

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 and require the Corporation to comply with greenhouse gas emissions legislation in Alberta or that may be enacted in other provinces. The Corporation may also be required comply with the regulatory scheme for greenhouse gas emissions ultimately adopted by the federal government, which regulations are expected to be consistent with the regulatory scheme for greenhouse gas emissions adopted by the United States. The direct or indirect costs of these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The future implementation or modification of greenhouse gases regulations, whether to meet the limits regulated by the Copenhagen Accord or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Corporation. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition. See "*Industry Conditions – Climate Change Regulation*".

Geo-Political Risks

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle East, North Africa and other areas of the world have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of the Corporation's net production revenue.

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

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to 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.

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, tax burden due to new 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. As a result of the global economic volatility, the Corporation, along with many other oil and natural gas entities, 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 or 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 materially and adversely affected 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.

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.

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.

Market Price of Common Shares

The trading price of securities of oil and natural gas issuers is subject to substantial volatility. This volatility is often based on factors both related and unrelated to the financial performance or prospects of the issuers involved. 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. Factors that could affect the market price of the Common Share that are unrelated to the Corporation's performance include domestic and global commodity prices and market perceptions of the attractiveness of particular industries. 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

Circumstances may arise where members of the board of directors of the Corporation are directors or officers of corporations which are in competition to the interests of the Corporation. No assurances can be given that opportunities identified by such board members will be provided to the Corporation.

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

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 an 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 financial statements and management's discussion and analysis for the year ended December 31, 2011.

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, 2011, 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) *"Kelly I. Drader"*
Kelly I. Drader
Chief Financial Officer

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

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

March 23, 2012

SCHEDULE "B"

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

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

1. We have evaluated the Company's Reserves Data as at December 31, 2011. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011, 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 and Longview Oil Corp. evaluated by us as of December 31, 2011, 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. and Longview Oil Corp.	Canada				
	As of December 31, 2011, prepared October 2011 to February 2012		nil	2,212,080	nil	2,212,080
Total			**nil**	**2,212,080**	**nil**	**2,212,080**

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
March 9, 2012

Original Signed by Cameron P. Six, P. Eng.
Cameron P. Six, P. Eng.
Vice President, Engineering and Partner

Original Signed by Lucia M. Precul, P. Eng
Lucia M. Precul, P.Eng
Senior Petroleum Engineer and Partner

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

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

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

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

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, 2011, December 31, 2010 and January 1, 2010, the consolidated statement of comprehensive income (loss), changes in shareholders' equity and cash flows for the years ended December 31, 2011 and 2010. The external auditors conducted their audits in accordance with Canadian generally accepted auditing standards and have unlimited and unrestricted access to the Audit Committee.

Andy J. Mah
President and CEO
March 23, 2012

Kelly I. Drader
CFO

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 issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on our assessment, we have concluded that as of December 31, 2011, 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, 2011, as stated in their Auditor's Report. PricewaterhouseCoopers LLP has provided such opinion.

Andy J. Mah
President and CEO
March 23, 2012

Kelly I. Drader
CFO

Independent Auditor's Report

To the Shareholders of Advantage Oil & Gas Ltd.

We have completed an integrated audit of Advantage Oil & Gas Ltd.'s 2011 consolidated financial statements and its internal control over financial reporting as at December 31, 2011 and an audit of its 2010 consolidated financial statements. 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, 2011, December 31, 2010 and January 1, 2010 and the consolidated statements of comprehensive income (loss), changes in shareholders' equity, and cash flows for the years ended December 31, 2011 and 2010, 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 an audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement. Canadian generally accepted auditing standards 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, 2011, December 31, 2010, and January 1, 2010 and its financial performance and its cash flows for the years ended December 31, 2011 and 2010 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, 2011 based on criteria established in Internal Control - Integrated Framework, 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.

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, 2011 based on criteria established in Internal Control - Integrated Framework issued by COSO.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta
March 23, 2012

Consolidated Statement of Financial Position

(thousands of Canadian dollars)	Notes	December 31, 2011	December 31, 2010	January 1, 2010
			(note 25)	(note 25)
ASSETS				
Current assets				
Trade and other receivables	7	$ 42,344	$ 42,276	$ 54,531
Prepaid expenses and deposits		6,045	6,488	9,936
Derivative asset	6	-	25,157	30,829
Total current assets		**48,389**	**73,921**	**95,296**
Non-current assets				
Derivative asset	6	-	-	323
Exploration and evaluation assets	8	7,730	8,262	6,923
Property, plant and equipment	9	1,877,287	1,883,762	1,824,699
Deferred income tax asset	22	39,383	-	-
Total non-current assets		**1,924,400**	**1,892,024**	**1,831,945**
Total assets		**$ 1,972,789**	**$ 1,965,945**	**$ 1,927,241**
LIABILITIES				
Current liabilities				
Trade and other accrued liabilities		$ 138,119	$ 112,457	$ 113,062
Capital lease obligations		-	759	1,375
Convertible debentures	12	-	62,013	69,927
Derivative liability	6	2,738	2,367	12,755
Other liability	14	908	-	-
Total current liabilities		**141,765**	**177,596**	**197,119**
Non-current liabilities				
Derivative liability	6	-	177	1,165
Capital lease obligations		-	-	759
Bank indebtedness	11	232,684	288,852	247,784
Convertible debentures	12	75,890	72,811	131,561
Decommissioning liability	13	253,796	172,130	169,665
Deferred income tax liability	22	29,723	40,231	22,115
Other liability	14	-	1,835	3,431
Total non-current liabilities		**592,093**	**576,036**	**576,480**
Total liabilities		**733,858**	**753,632**	**773,599**
SHAREHOLDERS' EQUITY				
Share capital	15	2,214,784	2,199,491	2,190,409
Convertible debentures equity component	12	8,348	8,348	8,348
Contributed surplus	5	71,762	14,783	6,114
Deficit		(1,163,081)	(1,010,309)	(1,051,229)
Total shareholders' equity attributable to Advantage shareholders		**1,131,813**	**1,212,313**	**1,153,642**
Non-controlling interest		107,118	-	-
Total shareholders' equity		**1,238,931**	**1,212,313**	**1,153,642**
Total liabilities and shareholders' equity		**$ 1,972,789**	**$ 1,965,945**	**$ 1,927,241**

Commitments (note 24)

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, 2011	Year ended December 31, 2010
			(note 25)
Petroleum and natural gas sales	18	$ 355,288	$ 319,368
Less: royalties		(52,971)	(45,954)
Petroleum and natural gas revenue		302,317	273,414
Operating expense		(89,166)	(95,609)
General and administrative expense	19	(34,587)	(38,193)
Depreciation expense	9	(152,927)	(124,592)
Impairment of oil and gas properties	9	(187,684)	(17,500)
Exploration and evaluation expense	8	(3,055)	(752)
Finance expense	21	(29,561)	(34,388)
Gains on derivatives	6	475	50,514
Other income	20	1,972	46,142
Income (loss) before taxes and non-controlling interest		**(192,216)**	**59,036**
Income tax recovery (expense)	22	46,807	(18,116)
Net income (loss) and comprehensive income (loss) before non-controlling interest		**(145,409)**	**40,920**
Net income attributable to non-controlling interest		(7,363)	-
Net income (loss) and comprehensive income (loss) attributable to Advantage shareholders		**$ (152,772)**	**$ 40,920**
Net income (loss) per share attributable to Advantage shareholders	17		
Basic		**$ (0.92)**	**$ 0.25**
Diluted		**$ (0.92)**	**$ 0.25**

See accompanying Notes to the Consolidated Financial Statements

Consolidated Statement of Changes in Shareholders' Equity

(thousands of Canadian dollars)	Notes	Share capital	Convertible debentures equity component	Contributed surplus	Deficit	Total shareholders' equity attributable to Advantage shareholders	Non-controlling interest	Total shareholders' equity
Balance, January 1, 2011		$ 2,199,491	$ 8,348	$ 14,783	$ (1,010,309)	**$ 1,212,313**	$ -	**$ 1,212,313**
Net income (loss) and comprehensive income (loss)		-	-	-	(152,772)	**(152,772)**	7,363	**(145,409)**
Share based compensation	15, 16	15,293	-	(770)	-	**14,523**	-	**14,523**
Common control transaction and change in ownership interest	5	-	-	57,749	-	**57,749**	106,093	**163,842**
Change in ownership interest, share based compensation		-	-	-	-	**-**	577	**577**
Dividends declared by Longview ($0.40 per Longview share)		-	-	-	-	**-**	(6,915)	**(6,915)**
Balance, December 31, 2011		**$ 2,214,784**	**$ 8,348**	**$ 71,762**	**$ (1,163,081)**	**$ 1,131,813**	**$ 107,118**	**$ 1,238,931**
Balance, January 1, 2010	25	$ 2,190,409	$ 8,348	$ 6,114	$ (1,051,229)	**$ 1,153,642**	$ -	**$ 1,153,642**
Share based compensation	15, 16	9,082	-	8,669	-	**17,751**	-	**17,751**
Net income and comprehensive income		-	-	-	40,920	**40,920**	-	**40,920**
Balance, December 31, 2010		**$ 2,199,491**	**$ 8,348**	**$ 14,783**	**$ (1,010,309)**	**$ 1,212,313**	**$ -**	**$ 1,212,313**

See accompanying Notes to the Consolidated Financial Statements

Consolidated Statement of Cash Flows

(thousands of Canadian dollars)	Notes		Year ended December 31, 2011		Year ended December 31, 2010
					(note 25)
Operating Activities					
Income (loss) before taxes and non-controlling interest		$	(192,216)	$	59,036
Add (deduct) items not requiring cash:					
Share based compensation	16		12,348		13,415
Depreciation expense	9		152,927		124,592
Impairment of oil and gas properties	9		187,684		17,500
Exploration and evaluation expense	8		3,055		752
Non-cash general and administrative			-		(538)
Unrealized loss (gain) on derivatives	6		25,351		(5,381)
Gain on sale of property, plant and equipment	20		(1,325)		(45,631)
Finance expense	21		29,561		34,388
Expenditures on decommissioning liability	13		(3,335)		(6,275)
Changes in non-cash working capital	23		4,131		31,008
Cash provided by operating activities			**218,181**		**222,866**
Financing Activities					
Proceeds from Longview financing	5		160,757		-
Increase (decrease) in bank indebtedness	11		(56,754)		40,395
Convertible debenture maturities	12		(62,294)		(69,927)
Dividends paid by Longview			(6,050)		-
Reduction of capital lease obligations			(68)		(1,375)
Convertible debenture issue costs			-		(310)
Interest paid			(20,076)		(21,532)
Cash provided by (used in) financing activities			**15,515**		**(52,749)**
Investing Activities					
Expenditures on property, plant and equipment	9		(231,789)		(237,702)
Expenditures on exploration and evaluation assets	8		(3,006)		(2,091)
Property dispositions			1,099		69,676
Cash used in investing activities			**(233,696)**		**(170,117)**
Net change in cash			-		-
Cash, beginning of year			-		-
Cash, end of year		$	-	$	-

See accompanying Notes to the Consolidated Financial Statements

For the years ended December 31, 2011 and 2010

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") are a growth oriented intermediate oil and natural gas development and production corporation with properties located in Western Canada.

Advantage is domiciled and incorporated in Canada under the Business Corporations Act (Alberta). Advantage's head office address is 700, 400 – 3rd 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 financial statements in accordance with Canadian generally accepted accounting principles as defined in the Handbook of the Canadian Institute of Chartered Accountants ("CICA Handbook"). In 2010, the CICA Handbook was revised to incorporate International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board and to require publicly accountable enterprises to apply these standards effective for years beginning on or after January 1, 2011. Accordingly, these consolidated financial statements are Advantage's first annual audited consolidated financial statements to be prepared and issued under IFRS.

The consolidated financial statements are prepared in compliance with IFRS. The comparative figures for 2010 and Advantage's financial position as at January 1, 2010 have been restated from previous Canadian Generally Accepted Accounting Principles ("Previous GAAP") to IFRS. The reconciliations to IFRS from Previous GAAP are summarized in note 25 and disclose the impact of the transition to IFRS on the Corporation's reported financial position and financial performance, including the nature and effect of significant changes in accounting policies from those used in the Corporation's consolidated financial statements for the year ended December 31, 2010. Subject to certain transition elections disclosed in note 25, the Corporation has consistently applied the same accounting policies in its opening IFRS statement of financial position at January 1, 2010 and throughout all periods presented, as if these policies had always been in effect.

The accounting policies applied in these financial statements are based on IFRS issued and outstanding as of March 23, 2012, 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 6.

(c) Functional and presentation currency

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

(d) Basis of consolidation

These consolidated financial statements include the accounts of the Corporation and all subsidiaries over which it has control, including Longview Oil Corp. ("Longview"), a public Canadian corporation of which Advantage owns 63%, and remaining ownership is disclosed as non-controlling interest. All inter-corporate balances, income and expenses resulting from inter-corporate transactions are eliminated.

3. Significant accounting policies

The accounting policies set out below have been applied consistently to all years presented in these financial statements, and have been applied consistently by the Corporation.

(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.

(b) Basis of consolidation

(i) Subsidiaries

Subsidiaries are entities controlled by the Corporation. Control exists when the Corporation has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. 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.

(ii) Non-controlling interests

The Corporation treats transactions with non-controlling interests as transactions with equity owners of the Corporation. For purchases of shares from non-controlling interests, the difference between any consideration paid and the relevant ownership acquired of the carrying value of net assets of the subsidiary is recorded in equity. Gains or losses on disposals of shares to non-controlling interests are also recorded in equity, unless the disposal results in the Corporation's loss of control of the subsidiary, in which case the gain or loss is recognized in net income and comprehensive income.

(iii) Joint interests

A significant portion of the Corporation's oil and natural gas activities involve jointly controlled assets. The consolidated financial statements include the Corporation's share of these jointly controlled assets 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 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 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 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 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 Statement of Financial Position.

3. Significant accounting policies (continued)

(c) Financial instruments (continued)

Transaction costs are frequently attributed to the acquisition or issue of a financial asset or liability. Such costs incurred on fair value through profit or loss financial instruments are expensed immediately. For other financial instruments, transaction costs are added to the fair value initially recognized for financial assets and liabilities that are not classified as fair value through profit or loss.

Embedded derivatives are separated from the host contract and accounted for separately if the economic characteristics and risks of the host contract and the embedded derivative are not closely related, a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative, and the combined instrument is not measured at fair value through profit or loss. Changes in the fair value of separable embedded derivatives are recognized immediately in income.

Equity instruments issued by the Corporation are recorded at the proceeds received, with direct issue costs as a deduction therefrom, net of any associated tax benefit.

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

(i) Recognition and measurement

a) Exploration and evaluation costs

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

All exploratory costs incurred subsequent to acquiring the right to explore for oil and natural gas and 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, decommissioning 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 and probable reserves are determined to exist. Upon determination of proved and 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.

b) Development and production costs

Items of property, plant and equipment, which include oil and gas development and production assets, 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 oil and natural gas interests, have different useful lives, they are accounted for as separate items (major components).

3. Significant accounting policies (continued)

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

(ii) Subsequent costs

Costs incurred subsequent to development and production that are significant are recognized as oil and gas 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 oil and natural gas interests 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 Statement of Comprehensive Income (Loss) as incurred.

(iii) Depreciation

The net carrying value of oil and gas properties is depreciated using the unit-of-production 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.

(e) Asset swaps and dispositions

Exchanges of development and production assets are measured at fair value unless the exchange transaction lacks commercial substance or the fair value of neither the asset received nor the asset given up is reliably measurable. The cost of the acquired asset is measured at the fair value of the asset given up, unless the fair value of the asset received is more clearly evident. Where fair value is not used, the cost of the acquired asset is measured at the carrying amount of the amount given up. Any gain or loss on derecognition of the asset given up is recognised in the Statement of Comprehensive Income (Loss).

For exchanges or parts of exchanges that involve only exploration and evaluation assets, the exchange is accounted for at carrying value.

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

(f) Impairment

(i) Financial assets

At each reporting date, the Corporation assesses whether there is objective evidence that a financial asset is impaired. If a financial asset carried at amortized cost is impaired, the amount of the loss is measured as the difference between the amortized cost of the loan or receivable and the present value of the estimated future cash flows, discounted using the instrument’s original effective interest rate. The loss is recognized in other expenses in the period incurred.

3. Significant accounting policies (continued)

(f) Impairment (continued)

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

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, then 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 to sell. 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 cost to sell 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 cost to sell 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 Statement of Comprehensive Income (Loss) as impairment of oil and gas properties and are separately disclosed. An impairment of exploration and evaluation assets is recognized as exploration and evaluation expense in the Statement of Comprehensive Income (Loss).

Impairment losses recognized in prior years are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation, if no impairment loss had been recognized.

(g) 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)

(h) Share based compensation

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

Advantage's Restricted Share Performance Incentive Plan ("RSPIP" or the "Plan"), authorizes the Board of Directors to grant restricted shares to service providers, including directors, officers, employees, and consultants of Advantage and Longview. The restricted share grants generally vest one-third immediately on grant date, with the remaining two-thirds vesting on each of the two subsequent anniversary dates. Compensation cost related to the Plan is recognized as share based compensation expense within general and administrative expense over the service period of the service providers and incorporates the fair value at grant date, the estimated number of restricted shares to vest, and certain management estimates. As compensation expense is recognized, contributed surplus is recorded until the restricted shares vest at which time the appropriate shares are then issued to the services providers and the contributed surplus is transferred to share capital.

(i) Common-control transaction

Business combinations involving entities under common control are outside the scope of IFRS 3 Business Combinations. IFRS provides no guidance on the accounting for these types of transactions and an entity is required to develop an accounting policy. The two most common methods utilized are the purchase method and the predecessor values method. A business combination involving entities under common control is a business combination in which all of the combining entities are ultimately controlled by the same party, both before and after the business combination, and control is not transitory. Management has determined the predecessor values method to be most appropriate. The predecessor method requires the financial statements to be prepared using the predecessor carrying values without any step up to fair value. The difference between any consideration and the aggregate carrying value of the assets and liabilities are recorded in shareholders' equity.

(j) Revenue

Revenue from the sale of petroleum and natural gas is recorded when the significant risks and rewards of ownership of the product is transferred to the buyer which is usually when legal title passes to the external party. For natural gas, this is generally at the time product enters the pipeline. For crude oil, this is generally at the time the product reaches a trucking terminal. For natural gas liquids, this is generally at the time the product reaches a gas plant. Revenue is measured net of discounts, customs duties and royalties.

Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

(k) Finance expense

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

3. Significant accounting policies (continued)

(l) Income tax

Income tax expense comprises current and deferred income tax. Income tax expense 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.

(m) 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 granted to service providers and convertible debentures, using the treasury stock method.

3. Significant accounting policies (continued)

(n) New standards and interpretations not yet adopted

Standards issued but not yet effective up to the date of issuance of the Corporation's financial statements are listed below. This listing is of standards and interpretations issued which the Corporation reasonably expects to be applicable at a future date. The Corporation intends to adopt those standards when they become effective. The Corporation has yet to assess the full impact of these standards.

IFRS 9 Financial Instruments: Classification and Measurement

IFRS 9 is intended to supersede IAS 39, Financial Instruments: Recognition and Measurement and will be published in three phases, of which the first phase has been published. The first phase addresses the accounting for financial assets and financial liabilities. The second phase will address the impairment of financial instruments, and the third phase will address hedge accounting. For financial assets, IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, and replaces the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39. For financial liabilities, although the classification criteria for financial liabilities will not change under IFRS 9, the approach to the fair value option for financial liabilities may require different accounting for changes to the fair value of a financial liability as a result of changes to an entity's own credit risk. This standard is not applicable until January 1, 2015.

IFRS 10 Consolidated Financial Statements

IFRS 10 is a new standard that will replace SIC 12, "Consolidation – Special Purpose Entities" and IAS 27 "Consolidated and Separate Financial Statements". The new standard eliminates the current risks and rewards approach and establishes control as the single basis for determining the consolidation of an entity. This standard is not applicable until January 1, 2013.

IFRS 11 Joint Arrangements

IFRS 11 requires a venture to classify its interest in a joint arrangement as a joint venture or joint operation. Joint ventures will be accounted for using the equity method of accounting whereas for a joint operation, the venture will recognize its share of the assets, liabilities, revenue and expenses. Under existing IFRS, entities have the choice to proportionately consolidate or equity account for interests in joint ventures. IFRS 11 supersedes IAS 31, Interests in Joint Ventures and SIC-13, Jointly Controlled Entities, Non-Monetary Contributions by Venturers. This standard is not applicable until January 1, 2013.

IFRS 12 Disclosure of Interests in Other Entities

IFRS 12 provides the required disclosures for interests in subsidiaries and joint arrangements. These disclosures will require information that will assist users of financial statements to evaluate the nature, risks and financial effects associated with an entity's interests in subsidiaries and joint arrangements. This standard is not applicable until January 1, 2013.

IFRS 13 – Fair Value Measurement

IFRS 13 is a comprehensive standard for fair value measurement and disclosure requirements for use across all IFRS standards. The new standard clarifies that fair value is the price that would be received to sell an asset, or paid to transfer a liability in an orderly transaction between market participants, at the measurement date. It also establishes disclosures about fair value measurement. Under existing IFRS, guidance on measuring and disclosing fair value is dispersed among the specific standards requiring fair value measurement and in many cases does not reflect a clear measurement basis or consistent disclosures. This standard is not applicable until January 1, 2013.

IAS 28 – Investments in Associates and Joint Ventures

IAS 28 has been amended to include joint ventures in its scope and to address the changes in IFRS 10 to 13.

4. Significant accounting judgments, estimates and assumptions

The preparation of 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.

Estimates and assumptions

Information about significant areas of estimation uncertainty in applying accounting policies that have the most significant effect on the amounts recognized in the consolidated financial statements is included in the following notes:

- Note 6 – valuation of financial instruments;
- Note 9 – valuation of property, plant and equipment;
- Note 8 & 9 – impairment of property, plant and equipment and exploration and evaluation assets;
- Note 6, 12 – valuation of convertible debentures;
- Note 13 – measurement of decommissioning liability;
- Note 16 – measurement of share based compensation; and
- Note 22 – measurement of deferred income tax.

Judgments

In the process of applying the Corporation's accounting policies, management has made the following judgments, apart from those involving estimates, which may have the most significant effect on the amounts recognized in the consolidated financial statements.

(a) Exploration and evaluation assets

Costs incurred to acquire rights to explore for oil and natural gas may be grouped into either exploration and evaluation or development and production, depending on facts and circumstances. Costs incurred in respect of properties that have been determined to have proved and probable reserves, are classified as development and production properties. In such circumstances, technical feasibility and commercial viability are considered to be established. Costs incurred in respect of new prospects with no nearby established development past or present and no proved or probable reserves assigned are classified as exploration and evaluation assets (note 8).

(b) Reserves base

The oil and gas development and production properties are depreciated on a unit-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 oil and natural gas in place, recovery factors and future oil and natural gas 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.

4. **Significant accounting judgments, estimates and assumptions (continued)**

(c) Depreciation of oil and gas assets

Oil and gas properties are depreciated using the UOP method over proved plus probable reserves. The calculation of the UOP rate of depreciation could be impacted to the extent that actual production in the future is different from current forecast production based on proved plus probable reserves (note 9).

(d) Determination of cash generating units

Oil and gas properties are grouped into cash generating units for purposes of impairment testing. Management has evaluated the oil and gas properties of the Corporation, and grouped the properties into cash generating units on the basis of their ability to generate independent cash flows, similar reserve characteristics, geographical location, and shared infrastructure.

(e) 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 to sell. 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 8 & 9).

(f) 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.

(g) Income taxes

The Corporation recognizes deferred income tax assets to the extent that it is probable that taxable profit will be available to allow the benefit of that deferred income tax asset to be utilized. Assessing the recoverability of deferred income tax assets requires the Corporation to make significant estimates related to expectations of future taxable income. Estimates of future taxable income are based on forecast cash flows from operations and the application of existing tax laws. To the extent that future cash flows and taxable income differ significantly from estimates, the ability of the Corporation to realize the deferred income tax assets recorded at the reporting date could be impacted. Additionally, future changes in tax laws in the jurisdictions in which the Corporation operates could limit the ability of the Corporation to obtain tax deductions in future periods.

(h) Contingencies

By their nature, contingencies will only be resolved when one or more future events occur or fail to occur. The assessment of contingencies inherently involves the exercise of significant judgment and estimates of the outcome of future events.

5. Common-Control Transaction

Advantage sold certain oil-weighted assets to Longview for total consideration of $546.9 million, comprised of 29,450,000 common shares of Longview representing a 63% equity ownership and $252.4 million in cash. The assets were sold with an effective date of January 1, 2011 and a closing date of April 14, 2011. As Advantage is the parent company and has a majority ownership interest of Longview, this transaction was deemed a common-control transaction. As such, Advantage has recognized a non-controlling interest in shareholders' equity, representing the carrying value of the 37% shareholding of Longview held by outside interests.

The difference of $57.7 million between the proceeds from the change in ownership interest and the carrying value of the non-controlling interest has been recognized within contributed surplus of shareholders' equity. At December 31, 2011, Advantage held 63% of Longview's issued and outstanding shares.

6. Financial risk management

Financial instruments of the Corporation include trade and other receivables, deposits, trade and other accrued liabilities, bank indebtedness, convertible debentures, other liabilities and derivative assets and liabilities.

Trade and other receivables and deposits are classified as loans and receivables and measured at amortized cost. Trade and other accrued liabilities, bank indebtedness and other liabilities are all classified as financial liabilities at amortized cost. As at December 31, 2011, there were no significant differences between the carrying amounts reported on the 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 convertible debenture obligations outstanding, of which the liability component has been classified as financial liabilities at amortized cost. The convertible debentures have different fixed terms and interest rates (note 12) resulting in fair values that will vary over time as market conditions change. As at December 31, 2011, the estimated fair value of the total outstanding convertible debenture obligation was $82.8 million (December 31, 2010 - $153.2 million). The fair value of the liability component of convertible debentures was determined based on the current public trading activity of such debentures.

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. Advantage uses Level 2 inputs in the determination of the fair value of 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. The actual gains and losses realized on eventual cash settlement can vary materially due to subsequent fluctuations in commodity prices 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.

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.

6. Financial risk management (continued)

(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 and oil and natural gas marketers. The maximum exposure to credit risk is as follows:

	December 31, 2011	December 31, 2010	January 1, 2010
Trade and other receivables	$ 42,344	$ 42,276	$ 54,531
Deposits	3,157	2,936	6,108
Derivative asset	-	25,157	31,152
	$ 45,501	**$ 70,369**	**$ 91,791**

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 primarily 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, 2011, $0.5 million or 1.2% of trade and other receivables are outstanding for 90 days or more (December 31, 2010 - $2.3 million or 5.4% 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, 2011 (December 31, 2010 - $0.2 million).

The Corporation's most significant customer, a Canadian oil and natural gas marketer, accounts for $12.3 million of the trade and other receivables at December 31, 2011 (December 31, 2010 - $12.1 million).

6. 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, other liabilities, and derivative liabilities. Trade and other accrued liabilities, other liabilities, and derivative liabilities are primarily due within one year of the 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 $475 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 convertible debentures outstanding that mature in 2015 (note 12). Interest payments are made semi-annually with excess cash provided by operating activities. As the debentures become due, the Corporation can satisfy the obligations in cash or issue shares at a price determined in the applicable debenture agreements. 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, 2011 and 2010 are as follows:

December 31, 2011		Less than one year	One to three years	Three to five years	Thereafter	Total
Trade and other accrued liabilities		$ 138,119	$ -	$ -	$ -	$ 138,119
Derivative liability		2,738	-	-	-	2,738
Bank indebtedness	- principal	-	233,903	-	-	233,903
	- interest	12,373	5,882	-	-	18,255
Convertible debentures	- principal	-	-	86,250	-	86,250
	- interest	4,313	8,625	2,156	-	15,094
Other liability		908	-	-	-	908
		$ 158,451	**$ 248,410**	**$ 88,406**	**$ -**	**$ 495,267**

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

December 31, 2010		Less than one year	One to three years	Four to five years	Thereafter	Total
Trade and other accrued liabilities		$ 112,457	$ -	$ -	$ -	$ 112,457
Capital lease obligations		779	-	-	-	779
Derivative liability		2,367	177	-	-	2,544
Bank indebtedness	- principal	-	290,657	-	-	290,657
	- interest	13,717	6,577	-	-	20,294
Convertible debentures	- principal	62,294	-	86,250	-	148,544
	- interest	9,179	8,625	6,469	-	24,273
Other liability		-	1,966	-	-	1,966
		$ 200,793	**$ 308,002**	**$ 92,719**	**$ -**	**$ 601,514**

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

6. Financial risk management (continued)

(b) Liquidity risk (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 reviews scheduled in April and June 2012. 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 crude oil prices used to calculate the fair value of the crude oil derivatives at December 31, 2011 would result in a $3.0 million change in net loss for the year ended December 31, 2011.

As at December 31, 2011, the Corporation had the following derivatives in place:

Description of Derivative	Term	Volume	Average Price
Crude oil - WTI			
Fixed price	January 2012 to December 2012	1,000 bbls/d	Cdn $97.10/bbl
Collar	January 2012 to December 2012	1,000 bbls/d	Bought put Cdn $90.00/bbl
			Sold call Cdn $102.25/bbl
Electricity – Alberta Pool Price			
Fixed price	January 2012 to December 2012	0.9 MW	Cdn $77.88/MWh

As at December 31, 2010 the Corporation had the following derivatives in place:

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

6. Financial risk management (continued)

(c) Price and currency risk (continued)

As at December 31, 2011, the fair value of the derivatives outstanding resulted in an asset of $Nil (December 31, 2010 – $25.2 million) and a liability of $2.7 million (December 31, 2010 – $2.5 million).

For the year ended December 31, 2011, $0.5 million was recognized in net loss as a derivative gain (December 31, 2010 - $50.5 million derivative gain). The table below summarizes the realized and unrealized gains (losses) on derivatives.

	Year ended December 31, 2011	Year ended December 31, 2010
Realized gains on derivatives	$ 25,826	$ 45,133
Unrealized gains (losses) on derivatives	(25,351)	5,381
	$ 475	**$ 50,514**

The fair value of the commodity risk management derivatives have been allocated to current and non-current assets and liabilities on the basis of expected timing of cash settlement and the applicable counterparties.

(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, 2011, net income (loss) and comprehensive income (loss) would have changed by $2.2 million (December 31, 2010 - $1.9 million) based on the average debt balance outstanding during the year.

6. **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, implementing a dividend reinvestment plan, adjusting capital spending, or disposing of assets or its ownership interest in Longview. The capital structure is reviewed by Management and the Board of Directors on an ongoing basis. Advantage's capital structure as at December 31, 2011, December 31, 2010 and January 1, 2010 is as follows:

($000, except as otherwise indicated)	**December 31, 2011**	**December 31, 2010**	**January 1, 2010**
Bank indebtedness (non-current) (note 11)	$ 233,903	$ 290,657	$ 250,262
Working capital deficit (1)	90,638	64,452	49,970
Net debt	$ 324,541	$ 355,109	$ 300,232
Shares outstanding (note 15)	166,304,040	164,092,009	162,745,528
Share closing market price ($/share)	4.24	6.76	6.90
Market capitalization (2)	705,129	1,109,262	1,122,944
Convertible debentures maturity value (current and non-current)	86,250	148,544	218,471
Capital lease obligations (non-current)	-	-	759
Total capitalization	**$ 1,115,920**	**$ 1,612,915**	**$ 1,642,406**

(1) Working capital deficit is a non-GAAP measure that includes trade and other receivables, prepaid expenses and deposits, trade and other accrued liabilities, the current portion of capital lease obligations, and current portion of other liability.
(2) Market capitalization is a non-GAAP measure calculated by multiplying shares outstanding by the closing market share price on the applicable date.

The Corporation's bank indebtedness is governed by credit facility agreements for $475 million (note 11) that contains standard commercial covenants for facilities of this nature. The only financial covenant is a requirement for Advantage to maintain a minimum cash flow to interest expense ratio of 3.5:1, determined on a rolling four quarter basis. The Corporation is in compliance with all credit facility covenants. As well, the borrowing base for the Corporation's credit facilities is determined through utilizing Advantage's regular reserve estimates. The banking syndicate thoroughly evaluates the reserve estimates based upon their own commodity price expectations to determine the amount of the borrowing base. Revision or changes in the reserve estimates and commodity prices can have either a positive or a negative impact on the borrowing base of the Corporation.

Management of the Corporation's capital structure is facilitated through its financial and operational forecasting processes. The forecast of the Corporation's future cash flows is based on estimates of production, commodity prices, forecast capital and operating expenditures, and other investing and financing activities. The forecast is regularly updated based on new commodity prices and other changes, which the Corporation views as critical in the current environment. Selected forecast information is frequently provided to the Board of Directors.

The Corporation's capital management objectives, policies and processes have remained unchanged during the years ended December 31, 2011 and 2010.

7. Trade and other receivables

	December 31, 2011	December 31, 2010	January 1, 2010
Trade receivables	$ 32,655	$ 30,997	$ 31,608
Receivables from joint venture partners	9,038	6,296	13,719
Other	651	4,983	9,204
	$ 42,344	**$ 42,276**	**$ 54,531**

8. Exploration and evaluation assets

Balance at January 1, 2010	$ 6,923
Additions	2,091
Exploration and evaluation expense	(752)
Balance at December 31, 2010	**$ 8,262**
Additions	3,006
Transferred to property, plant and equipment (note 9)	(483)
Exploration and evaluation expense	(3,055)
Balance at December 31, 2011	**$ 7,730**

There were no indicators of impairment of exploration and evaluation assets during the years ended December 31, 2011 and 2010.

9. Property, plant and equipment

Cost	Oil & gas properties	Furniture and equipment	Total
Balance at January 1, 2010	$ 1,821,078	$ 3,621	$ 1,824,699
Additions	221,280	403	221,683
Change in decommissioning liability (note 13)	37,073	-	37,073
Disposals	(60,482)	-	(60,482)
Balance at December 31, 2010	**$ 2,018,949**	**$ 4,024**	**$ 2,022,973**
Additions	253,731	443	254,174
Change in decommissioning liability (note 13)	79,660	-	79,660
Disposals	(184)	-	(184)
Transferred from exploration and evaluation assets (note 8)	483	-	483
Balance at December 31, 2011	**$ 2,352,639**	**$ 4,467**	**$ 2,357,106**

Accumulated depreciation and impairment losses	Oil & gas properties	Furniture and equipment	Total
Balance at January 1, 2010	$ -	$ -	$ -
Depreciation	123,360	1,232	124,592
Impairment of oil and gas properties	17,500	-	17,500
Disposals	(2,881)	-	(2,881)
Balance at December 31, 2010	**$ 137,979**	**$ 1,232**	**$ 139,211**
Depreciation	152,279	648	152,927
Impairment of oil and gas properties	187,684	-	187,684
Disposals	(3)	-	(3)
Balance at December 31, 2011	**$ 477,939**	**$ 1,880**	**$ 479,819**

Net book value	Oil & gas properties	Furniture and equipment	Total
At January 1, 2010	$ 1,821,078	$ 3,621	$ 1,824,699
At December 31, 2010	$ 1,880,970	$ 2,792	$ 1,883,762
At December 31, 2011	$ 1,874,700	$ 2,587	$ 1,877,287

During the year ended December 31, 2011, Advantage capitalized general and administrative expenditures directly related to development activities of $7.6 million (December 31, 2010 - $8.9 million).

Advantage included future development costs of $1.7 billion (December 31, 2010 – $1.6 billion) in property, plant and equipment costs subject to depreciation.

9. Property, plant and equipment (continued)

For the year ended December 31, 2011, Advantage recognized an impairment of oil and gas properties of $187.7 million (December 31, 2010 - $17.5 million). Impairment of oil and gas properties occur when management determines that indicators of impairment are present in specific cash generating units. Recorded impairments are the amount by which carrying amounts of the cash generating units exceed their respective recoverable amount based on a fair value less costs to sell determination. Fair value less costs to sell is based on discounted after-tax future net cash flows of proved and probable reserves using forecast prices and costs, discounted at 10%.

Forecast natural gas prices used in the calculation of impairment of oil and gas properties for the year ended December 31, 2011 are as follows:

Year	AECO ($Cdn/MMBtu)
2012	3.16
2013	3.78
2014	4.13
2015	5.53
2016	5.65
2017	5.77
2018	5.89
2019	6.01
2020	6.14
2021 (1)	6.27

(1) Escalation of 1.5% thereafter

The impairment of oil and gas properties recognized in the year ended December 31, 2011 relates to natural gas producing assets in West and East Alberta. The decline in the price of natural gas was considered to be an indicator of impairment.

The impairment of oil and gas properties recognized in the year ended December 31, 2010 related to a West Alberta oil cash generating unit, that was subject to negative reserve revisions at year end.

10. Related party transactions

Transactions between Advantage and Longview

Advantage sold certain oil-weighted properties to Longview on April 14, 2011 (note 5).

Concurrent with the disposition, Advantage entered into a Technical Services Agreement (“TSA”) with Longview. Under the TSA, Advantage provides the necessary personnel and technical services to manage Longview’s business and Longview reimburses Advantage on a monthly basis for its share of administrative charges based on respective levels of production. All amounts paid are recorded as general and administrative expenses and measured at the exchange amount, which is the amount agreed upon by the transacting parties.

At December 31, 2011, amounts due from Longview totaled $1.7 million (December 31, 2010 - $Nil). Advantage charged Longview $3.8 million during the year ended December 31, 2011 under the TSA. Dividends declared and paid or payable from Longview to Advantage during the year ended December 31, 2011 totaled $11.8 million (December 31, 2010 - $Nil). All amounts due to and from Longview are non-interest bearing in nature, are settled monthly and were incurred within the normal course of business. All inter-corporate balances, income and expenses resulting from inter-corporate transactions are eliminated.

Key management compensation

The compensation paid or payable to key management, including directors, is as follows:

	December 31, 2011	December 31, 2010
Salaries, director fees and short-term benefits	$ 4,821	$ 4,786
Other long-term benefits	-	-
Share based compensation (1)	5,067	8,242
	$ 9,888	$ 13,028

(1) Represents the grant date fair value of Restricted Shares granted under the RSPIP for the respective years.

11. Bank indebtedness

	December 31, 2011	December 31, 2010	January 1, 2010
Revolving credit facility	$ 233,903	$ 290,657	$ 250,262
Discount on Bankers Acceptances and other fees	(1,219)	(1,805)	(2,478)
Balance, end of year	**$ 232,684**	**$ 288,852**	**$ 247,784**

The Corporation has credit facilities (the "Credit Facilities") of $475 million, comprised of $275 million held by Advantage and $200 million held by Longview. The Credit Facilities are comprised of $40 million extendible revolving operating loan facilities from one financial institution and $435 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 Corporations' debt to cash flow ratio. The Credit Facilities are each 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 April and June 2012 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 non-revolving term facilities 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 three years. Further, the aggregate of such contracts cannot hedge greater than 60% of total estimated petroleum and natural gas production over two years and 50% over the third year, in each respective legal entity. The Credit Facilities contain standard commercial covenants for credit facilities of this nature. The only financial covenant is a requirement for each entity 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, 2011, December 31, 2010, and January 1, 2010. 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, 2011, the average effective interest rate on the outstanding amounts under the facility was approximately 5.3% (December 31, 2010 – 5.0%). Advantage also has issued letters of credit totaling $8.8 million at December 31, 2011 (December 31, 2010 – $2.9 million).

12. Convertible debentures

The convertible unsecured subordinated debentures pay interest semi-annually and are 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 debentures including fair market values initially assigned and issuance costs are as follows:

	6.50%	**7.75%**	**8.00%**	**5.00%**
Trading symbol	AAV.DBE	AAV.DBD	AAV.DBG	AAV.DBH
Issue date	May 18, 2005	Sep. 15, 2004	Nov. 13, 2006	Dec. 31, 2009
Maturity date	June 30, 2010	Dec. 1, 2011	Dec. 31, 2011	Jan. 30, 2015
Conversion price	$ 24.96	$ 21.00	$ 20.33	$ 8.60
Liability component	$ 69,952	$ 50,000	$ 41,445	$ 73,019
Equity component	-	-	-	13,231
Gross proceeds	69,952	50,000	41,445	86,250
Issuance costs	-	(2,190)	-	(3,735)
Net proceeds	**$ 69,952**	**$ 47,810**	**$ 41,445**	**$ 82,515**

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

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

12. Convertible debentures (continued)

The balance of debentures outstanding at December 31, 2011 and changes in the liability and equity components during the years ended December 31, 2011 and 2010 are as follows:

	6.50%	7.75%
Trading symbol	AAV.DBE	AAV.DBD
Debentures outstanding	$ -	$ -
Liability component:		
Balance at January 1, 2010	**$ 69,927**	**$ 46,176**
Accretion of discount	-	309
Matured	(69,927)	-
Balance at December 31, 2010	**-**	**46,485**
Accretion of discount	-	281
Matured	-	(46,766)
Balance at December 31, 2011	**$ -**	**$ -**

	8.00%	5.00%	Total
Trading symbol	AAV.DBG	AAV.DBH	
Debentures outstanding	$ -	$ 86,250	$ 86,250
Liability component:			
Balance at January 1, 2010	**$ 15,528**	**$ 69,857**	**$ 201,488**
Accretion of discount	-	2,954	3,263
Matured	-	-	(69,927)
Balance at December 31, 2010	**15,528**	**72,811**	**134,824**
Accretion of discount	-	3,079	3,360
Matured	(15,528)	-	(62,294)
Balance at December 31, 2011	**$ -**	**$ 75,890**	**$ 75,890**
Equity component:			
Balance at January 1, 2010	**$ -**	**$ 8,348**	**$ 8,348**
Balance at December 31, 2010	**$ -**	**$ 8,348**	**$ 8,348**
Balance at December 31, 2011	**$ -**	**$ 8,348**	**$ 8,348**

The principal amount of 7.75% convertible debentures matured on December 1, 2011, and was settled with $46.8 million in cash. The principal amount of 8.00% convertible debentures matured on December 31, 2011, and was settled with $15.5 million in cash. The principal amount of 6.50% convertible debentures matured on June 30, 2010 and was settled with $69.9 million in cash. There were no conversions of convertible debentures during the years ended December 31, 2011 and 2010.

13. Decommissioning liability

The Corporation's decommissioning liability results from net ownership interests in petroleum and natural gas 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 2012 and 2071. A risk-free rate of 2.50% (December 31, 2010 – 3.54%) and an inflation factor of 2% were used to calculate the fair value of the decommissioning liability.

A reconciliation of the decommissioning liability is provided below:

	Year ended December 31, 2011	Year ended December 31, 2010
Balance, beginning of year	$ 172,130	$ 169,665
Accretion expense	5,748	6,094
Liabilities incurred	4,714	3,331
Change in estimates	(3,699)	6,601
Effect of change in risk-free rate	78,645	27,141
Property dispositions	(407)	(34,427)
Liabilities settled	(3,335)	(6,275)
Balance, end of year	**$ 253,796**	**$ 172,130**

14. Other liability

The Corporation has a non-cancellable lease for office space which, due to changes in its activities, the Corporation ceased to use in September 2009, while the lease expires in 2012. Management considers this to be an onerous contract, therefore the obligation for the discounted future payments, net of expected rental income, has been provided for as a liability.

A reconcilation of the other liability is as follows:

	Year ended December 31, 2011	Year ended December 31, 2010
Balance, beginning of year	$ 1,835	$ 3,431
Accretion expense (note 21)	99	199
Reduction of liability by subleasing space	-	(538)
Liability settled	(1,026)	(1,257)
Balance, end of year	**$ 908**	**$ 1,835**

15. Share capital

(a) Authorized

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

(b) Issued

	Number of Shares	Amount
Balance at January 1, 2010	162,745,528	$ 2,190,409
Share based compensation (note 16)	1,346,481	9,082
Balance at December 31, 2010	164,092,009	$ 2,199,491
Share based compensation (note 16)	2,212,031	15,293
Balance at December 31, 2011	166,304,040	$ 2,214,784

16. Share based compensation

Advantage has a Restricted Share Performance Incentive Plan (“RSPIP” or the “Plan”) as approved by the shareholders. The Plan authorizes the Board of Directors to grant restricted shares to service providers, including directors, officers, employees, and consultants of Advantage. The number of restricted shares granted is based on the Corporation’s share price return for a twelve-month period and compared to the performance of a peer group approved by the Board of Directors. The share price return is calculated at the end of each and every quarter and is primarily based on the twelve-month change in the share price. If the share price return for a twelve-month period is positive, a restricted share grant will be calculated based on the return. Otherwise, no restricted shares will be granted to service providers for the period. If the share price return for a twelve-month period is negative, but the return is still within the top two-thirds of the approved peer group performance, the Board of Directors may grant a discretionary restricted share award. The restricted share grants generally vest one-third immediately on grant date, with the remaining two-thirds vesting on each of the two subsequent anniversary dates. On vesting, common shares are issued to the service providers in exchange for the restricted shares outstanding. The holders of restricted shares may elect to receive cash upon vesting in lieu of the number of shares to be issued, subject to consent of the Corporation. However, it is the intent to settle unvested amounts with shares.

The following table is a continuity of restricted shares:

	Restricted Shares
Balance at January 1, 2010	2,226,904
Granted	2,547,020
Vested	(1,818,707)
Forfeited	(29,349)
Balance at December 31, 2010	2,925,868
Granted	1,443,956
Vested	(2,212,031)
Forfeited	(40,083)
Balance at December 31, 2011	2,117,710

The following table summarizes information about restricted shares outstanding at December 31, 2011:

Date Granted	Number of Restricted Shares	Weighted Average Fair Value at Grant Date
September 2, 2009	344,353	$ 5.80
January 12, 2010	247,439	$ 7.27
April 12, 2010	314,232	$ 6.97
July 12, 2010	257,010	$ 6.53
January 12, 2011	43,955	$ 6.95
April 11, 2011	539,263	$ 8.28
July 12, 2011	371,458	$ 7.15
Total	2,117,710	

During the year ended December 31, 2011, the Corporation recognized share based compensation of $15.1 million (December 31, 2010 - $19.9 million), of which $2.8 million (December 31, 2010 - $3.9 million) was capitalized to property, plant and equipment, and $12.3 million (December 31, 2010 - $16.0 million) was recorded as an expense in the Statement of Income (Loss) and Comprehensive Income (Loss).

17. 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, 2011	Year ended December 31, 2010
Net income (loss) attributable to Advantage shareholders		
Basic	$ (152,772)	$ 40,920
Restricted shares (note 16)	-	-
Convertible debentures	-	-
Diluted	$ (152,772)	$ 40,920
Weighted average shares outstanding		
Basic	165,370,777	163,467,225
Restricted shares (note 16)	-	1,094,135
Convertible debentures	-	-
Diluted	165,370,777	164,561,360

The calculation of diluted net income (loss) per share for the years ended December 31, 2011 and 2010 excludes convertible debentures, as their impact would be anti-dilutive. Total weighted average shares issuable in exchange for the series of convertible debentures excluded from the diluted net income (loss) per share calculation for the year ended December 31, 2011 was 12,828,588 (year ended December 31, 2010 – 14,401,412 shares). As at December 31, 2011, the total convertible debentures outstanding were immediately convertible to 10,029,070 shares (December 31, 2010 – 13,019,819 shares).

Restricted shares have been excluded from the calculation of diluted net loss per share for the year ended December 31, 2011, as the impact would have been anti-dilutive. Total weighted average shares issuable in exchange for the restricted shares and excluded from the diluted net loss per share calculation for the year ended December 31, 2011 was 1,192,566 shares.

18. Petroleum and natural gas sales

	Year ended December 31, 2011	Year ended December 31, 2010
Crude oil and natural gas liquid sales	$ 186,014	$ 172,796
Natural gas sales	169,274	146,572
Total petroleum and natural gas sales	**$ 355,288**	**$ 319,368**

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

	Year ended December 31, 2011	Year ended December 31, 2010
Salaries and benefits	$ 20,778	$ 20,334
Share based compensation (notes 15,16)	15,100	19,851
Office rent	2,337	2,192
Other	3,955	4,755
Total G&A	**42,170**	**47,132**
Capitalized (note 9)	(7,583)	(8,939)
Net G&A	**$ 34,587**	**$ 38,193**

20. Other income

	Year ended December 31, 2011	Year ended December 31, 2010
Gain on sale of property, plant and equipment	$ 1,325	$ 45,631
Miscellaneous income	647	511
Total other income	**$ 1,972**	**$ 46,142**

21. Finance expense

	Year ended December 31, 2011	Year ended December 31, 2010
Interest on bank indebtedness	$ 11,483	$ 13,346
Interest on convertible debentures	8,871	11,486
Accretion on convertible debentures (note 12)	3,360	3,263
Accretion of decomissioning liability (note 13)	5,748	6,094
Accretion of other liability (note 14)	99	199
Total finance expense	$ 29,561	$ 34,388

22. Income taxes

The provision for income taxes is as follows:

	Year ended December 31, 2011	Year ended December 31, 2010
Current income tax expense	$ -	$ -
Deferred income tax expense (recovery)	(46,807)	18,116
Income tax expense (recovery)	$ (46,807)	$ 18,116

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, 2011	Year ended December 31, 2010
Income (loss) before taxes and non-controlling interest	$ (192,216)	$ 59,036
Combined federal and provincial income tax rates	26.57%	28.17%
Expected income tax expense (recovery)	(51,072)	16,630
Increase (decrease) in income taxes resulting from:		
Non-deductible share based compensation	4,031	5,162
Difference between current and expected tax rates	234	(3,676)
	$ (46,807)	$ 18,116
Effective tax rate	24.35%	30.69%

The Canadian combined statutory tax rates decreased from 28.17% in 2010 to 26.57% in 2011 as a result of legislation enacted in 2007.

22. Income taxes (continued)

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 January 1, 2010	$ 194,515	$ 4,867	$ 199,382
Charged (credited) to income	47,597	1,166	48,763
Balance at December 31, 2010	242,112	6,033	248,145
Charged (credited) to income	(3,771)	(6,737)	(10,508)
Balance at December 31, 2011	$ 238,341	$ (704)	$ 237,637

Deferred income tax asset	Decommissioning liability	Non-capital losses	Other	Total
Balance at January 1, 2010	$ (42,910)	$ (127,941)	$ (6,416)	$ (177,267)
Charged (credited) to income	(581)	(31,417)	1,351	(30,647)
Balance at December 31, 2010	(43,491)	(159,358)	(5,065)	(207,914)
Charged (credited) to income	(20,444)	(15,970)	115	(36,299)
Charged (credited) to equity	-	(1,091)	(1,993)	(3,084)
Balance at December 31, 2011	$ (63,935)	$ (176,419)	$ (6,943)	$ (247,297)

Net deferred income tax liability (asset)	Longview	Advantage	Total
Balance at January 1, 2010	$ -	$ 22,115	$ 22,115
Charged (credited) to income	-	18,116	18,116
Balance at December 31, 2010	-	40,231	40,231
Charged (credited) to income	(36,299)	(10,508)	(46,807)
Charged (credited) to equity	(3,084)	-	(3,084)
Balance at December 31, 2011	$ (39,383)	$ 29,723	$ (9,660)

The net deferred income tax asset is expected to reverse within 12 months.

The estimated tax pools available at December 31, 2011 are as follows:

	Longview	Advantage	Total
Canadian development expenses	$ 35,402	$ 105,300	$ 140,702
Canadian exploration expenses	-	70,761	70,761
Canadian oil and gas property expenses	366,793	-	366,793
Non-capital losses	72,582	631,660	704,242
Undepreciated capital cost	76,362	271,190	347,552
Other	7,911	5,951	13,862
	$ 559,050	$ 1,084,862	$ 1,643,912

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

23. Supplemented cash flow information

Changes in non-cash working capital is comprised of:

	Year ended December 31, 2011	Year ended December 30, 2010
Source (use) of cash:		
Trade and other receivables	$ (68)	$ 12,255
Prepaid expenses and deposits	443	3,448
Trade and other accrued liabilities	25,662	(605)
	$ 26,037	$ 15,098
Related to operating activities	$ 4,131	$ 31,008
Related to financing activities	2,274	2,408
Related to investing activities	19,632	(18,318)
	$ 26,037	$ 15,098

24. Commitments

Advantage has several lease commitments relating to office buildings and transportation. The estimated remaining annual minimum operating lease payments are as follows, of which $0.9 million is recognized in other liability (note 14):

	December 31, 2011	December 31, 2010
2011	$ -	$ 11,756
2012	15,543	11,791
2013	14,413	10,576
2014	11,812	8,723
2015	2,246	2,108
	$ 44,014	**$ 44,954**

25. Transition to IFRS

For all periods up to and including the year ended December 31, 2010 the Corporation prepared its financial statements in accordance with previous Canadian generally accepted accounting principles (“Previous GAAP”). These financial statements, for the year ended December 31, 2011, are prepared in accordance with International Financial Reporting Standards (“IFRS”). The Corporation has prepared financial statements which comply with IFRS applicable for periods beginning on or after January 1, 2010 and the significant accounting policies meeting those requirements are described in note 3. The Corporation has prepared its IFRS opening balance sheet as at January 1, 2010, its date of transition to IFRS.

IFRS 1 allows first-time adopters certain exemptions from the general requirement to apply IFRS retrospectively. The Corporation has taken the following exemptions:

- Companies using full-cost accounting are allowed to measure their oil and gas assets at the amount determined under the Previous GAAP at the date of transition. This amount is pro-rated to the underlying assets based upon the value of proved and probable reserves at transition date, discounted at 10%.

- Companies using the full cost book value as deemed cost exemption are allowed to measure the liabilities for decommissioning, restoration and similar liabilities at the date of transition and recognize directly in retained earnings any difference between that amount and the carrying amount determined under Previous GAAP.

- IFRS 3 Business Combinations has not been applied to acquisitions of subsidiaries or of interests in associates and joint ventures that occurred before January 1, 2010.

- IFRS 2 Share-based Payment has not been applied to any equity instruments that were granted on or before November 7, 2002, nor has it been applied to equity instruments granted after November 7, 2002 that vested before January 1, 2010.

- IAS 17 Leases has been applied as of transition date rather than at the lease’s inception date.

- IAS 32 Financial Instruments Presentation will not be applied for compound financial instruments where the liability component is no longer outstanding.

- IAS 23 Borrowing Costs will not be applied before January 1, 2010.

Reconciliations to IFRS from Previous GAAP financial statements including the impact of the transitioning on the Corporation’s reported financial position and financial performance, including the nature and effect of significant changes in accounting policies are summarized as follows.

25. Transition to IFRS (continued)

Reconciliation of Consolidated Statement of Financial Position at the date of IFRS transition, January 1, 2010.

(thousands of Canadian dollars)	Notes	Previous GAAP	Effect of Transition to IFRS	IFRS Reclassifications	IFRS
ASSETS					
Current assets					
Trade and other receivables		$ 54,531	$ -	$ -	$ 54,531
Prepaid expenses and deposits		9,936	-	-	9,936
Derivative asset		30,829	-	-	30,829
Total current assets		**95,296**	**-**	**-**	**95,296**
Non-current assets					
Derivative asset		323	-	-	323
Exploration and evaluation assets	2	-	-	6,923	6,923
Property, plant and equipment	2	1,831,622	-	(6,923)	1,824,699
Total non-current assets		**1,831,945**	**-**	**-**	**1,831,945**
Total assets		**$ 1,927,241**	**$ -**	**$ -**	**$ 1,927,241**
LIABILITIES					
Current liabilities					
Trade and other accrued liabilities	6	$ 111,901	$ -	$ 1,161	$ 113,062
Capital lease obligations		1,375	-	-	1,375
Convertible debentures	4	69,553	374	-	69,927
Derivative liability		12,755	-	-	12,755
Deferred income tax liability	5	4,704	-	(4,704)	-
Total current liabilities		**200,288**	**374**	**(3,543)**	**197,119**
Non-current liabilities					
Derivative liability		1,165	-	-	1,165
Capital lease obligations		759	-	-	759
Bank indebtedness		247,784	-	-	247,784
Convertible debentures	4	130,658	903	-	131,561
Decommissioning liability	3	68,555	101,110	-	169,665
Deferred income tax liability	5	38,796	(21,385)	4,704	22,115
Other liability		3,431	-	-	3,431
Total non-current liabilities		**491,148**	**80,628**	**4,704**	**576,480**
Total liabilities		**691,436**	**81,002**	**1,161**	**773,599**
SHAREHOLDERS' EQUITY					
Share capital		2,190,409	-	-	2,190,409
Convertible debentures equity component	4	18,867	(10,519)	-	8,348
Contributed surplus	6	7,275	-	(1,161)	6,114
Deficit		(980,746)	(70,483)	-	(1,051,229)
Total shareholders' equity		**1,235,805**	**(81,002)**	**(1,161)**	**1,153,642**
Total liabilities and shareholders' equity		**$ 1,927,241**	**$ -**	**$ -**	**$ 1,927,241**

25. Transition to IFRS (continued)

Reconciliation of Consolidated Statement of Financial Position at the end of the last reporting year under Previous GAAP, December 31, 2010.

(thousands of Canadian dollars)	Notes	Previous GAAP	Effect of Transition to IFRS	IFRS Reclassifiications	IFRS
ASSETS					
Current assets					
Trade and other receivables		$ 42,276	$ -	$ -	$ 42,276
Prepaid expenses and deposits		6,488	-	-	6,488
Derivative asset		25,157	-	-	25,157
Total current assets		**73,921**	**-**	**-**	**73,921**
Non-current assets					
Exploration and evaluation assets	2	-	-	8,262	8,262
Property, plant and equipment	1, 2, 3	1,768,650	123,374	(8,262)	1,883,762
Total non-current assets		**1,768,650**	**123,374**	**-**	**1,892,024**
Total assets		**$ 1,842,571**	**$ 123,374**	**$ -**	**$ 1,965,945**
LIABILITIES					
Current liabilities					
Trade and other accrued liabilities		$ 112,457	$ -	$ -	$ 112,457
Capital lease obligations		759	-	-	759
Convertible debentures	4	61,570	443	-	62,013
Derivative liability		2,367	-	-	2,367
Deferred income tax liability	5	5,876	-	(5,876)	-
Total current liabilities		**183,029**	**443**	**(5,876)**	**177,596**
Non-current liabilities					
Derivative liability		177	-	-	177
Bank indebtedness		288,852	-	-	288,852
Convertible debentures		72,811	-	-	72,811
Decommissioning liability	3	58,281	113,849	-	172,130
Deferred income tax liability	5	29,399	4,956	5,876	40,231
Other liability		1,835	-	-	1,835
Total non-current liabilities		**451,355**	**118,805**	**5,876**	**576,036**
Total liabilities		**634,384**	**119,248**	**-**	**753,632**
SHAREHOLDERS' EQUITY					
Share capital		2,199,491	-	-	2,199,491
Convertible debentures equity component	4	15,896	(7,548)	-	8,348
Contributed surplus	4	17,754	(2,971)	-	14,783
Deficit		(1,024,954)	14,645	-	(1,010,309)
Total shareholders' equity		**1,208,187**	**4,126**	**-**	**1,212,313**
Total liabilities and shareholders' equity		**$ 1,842,571**	**$ 123,374**	**$ -**	**$ 1,965,945**

25. Transition to IFRS (continued)

Reconciliation of Consolidated Statement of Comprehensive Income (Loss) for the year ended December 31, 2010:

(thousands of Canadian dollars)	Notes	Previous GAAP	Effect of Transition to IFRS	IFRS Reclassifications	IFRS
Petroleum and natural gas sales		$ 319,368	$ -	$ -	$ 319,368
Less: royalties	8	(44,640)	-	(1,314)	(45,954)
Petroleum and natural gas revenue		274,728	-	(1,314)	273,414
Operating expense	1c	(93,875)	(1,734)	-	(95,609)
General and administrative expense	1c	(37,578)	(615)	-	(38,193)
Depreciation expense	1, 7	(215,780)	86,695	4,493	(124,592)
Impairment of oil and gas properties	1d	-	(17,500)	-	(17,500)
Exploration and evaluation expense	2	-	(752)	-	(752)
Finance expense	3, 4, 7	(29,128)	(767)	(4,493)	(34,388)
Gains on derivatives		50,514	-	-	50,514
Other income	1a	-	46,142	-	46,142
Income (loss) before taxes		**(51,119)**	**111,469**	**(1,314)**	**59,036**
Income tax recovery (expense)	5, 8	6,911	(26,341)	1,314	(18,116)
Net income (loss) and comprehensive income (loss)		**$ (44,208)**	**$ 85,128**	**$ -**	**$ 40,920**
Net income (loss) per share					
Basic		$ (0.27)			$ 0.25
Diluted		$ (0.27)			$ 0.25

1. Property, Plant and Equipment

   a. Gain on sale of property, plant and equipment
   Under Previous GAAP, the Corporation did not recognize gains or losses on the disposal of oil and gas properties unless such dispositions would change the depletion rate by 20% or more while IFRS does require such recognition. This results in an increase to the carrying value and a gain on sale of property, plant and equipment included in other income.

   b. Depreciation expense
   Under Previous GAAP, depletion and depreciation was calculated on a unit-of-production basis for oil and gas properties using proved reserves, on a cost center basis that was defined as a country. Under IFRS, depreciation is calculated based on proved and probable reserves over individual components resulting in a decrease in depreciation expense and increase in the carrying value of property, plant and equipment.

   c. Capitalization
   During the transition to IFRS, revisions and refinements were made to capitalization. As a result, certain expenditures incurred in 2010 were expensed as operating expense and general and administrative expense.

   d. Impairment
   At December 31, 2010 an impairment loss was recognized associated with a cash generating unit located in West Central Alberta that was subject to negative reserve revisions at year end. The cash generating unit was written down to fair value less costs to sell, determined on a discounted cash flow model, using a discount rate of 10%.

25. Transition to IFRS (continued)

2. Exploration and evaluation assets

   Under Previous GAAP, exploration and evaluation assets were included in the full cost pool of property, plant and equipment. Under IFRS, these assets must be reclassified from developed oil and natural gas property, plant and equipment and presented separately. When exploration and evaluation assets are determined to be technically feasible and commercially viable, the costs are moved to developed oil and natural gas property, plant and equipment. Assets that are not technically feasible and commercially viable are expensed.

3. Decommissioning liability

   Under Previous GAAP asset retirement obligations were discounted at a credit-adjusted risk-fee rate. Under IFRS the discount rate has been reduced to a risk-free rate of 4.00% on January 1, 2010. Accordingly, the decommissioning liability has increased by $101.1 million at transition date, and due to the exemption allowed by IFRS 1, the offsetting charge has been recognized in deficit. As a result, under IFRS both the accretion expense associated with the decommissioning liability will be different and changes in the estimate of the decommissioning liability will impact property, plant and equipment.

4. Convertible debentures liability component

   Prior to July 9, 2009, Advantage was an Income Trust that operated under the name Advantage Energy Income Fund. As an income trust, convertible debentures were convertible into Trust Units, which contained a redemption feature which effectively made the conversion option a "putable instrument" under IAS 32. As such, convertible debentures were liabilities, with no equity component. Upon conversion to a corporation on July 9, 2009, all convertible debentures became convertible into common shares, and were no longer deemed to contain a "putable instrument". Retrospective restatement of the convertible debentures in existence at July 9, 2009 and still outstanding at transition date resulted in the liability component restated to their full maturity values, less any issue costs and no value assigned to the equity component of the conversion features of these same debentures. Accretion expense as recorded under Previous GAAP was reduced, as only debenture issue costs gave rise to accretion expense for these convertible debentures.

5. Deferred income tax liability:

   a. Deferred income tax calculated according to IFRS is substantially similar to Previous GAAP and arises from differences between the accounting and tax bases of our assets and liabilities. To the extent that assets and liabilities have changed from transition to IFRS, the amount of deferred income tax liability would be impacted.

   b. Under Previous GAAP, deferred income tax liabilities were required to be disclosed as either current or long-term. Under IFRS, all deferred income tax liabilities are considered to be non-current liabilities.

6. Contributed surplus

   At January 1, 2010, a portion of unvested RSPIP compensation costs included in contributed surplus effectively represented cash payments. Under IFRS, this portion was considered a liability and accordingly reclassified to trade and other accrued liabilities.

7. Finance expense

   Under Previous GAAP, accretion of decommissioning liability was included in the amount presented as depreciation of property, plant and equipment on the Statement of Income and Comprehensive Income. Under IFRS, accretion of decommissioning liability has been reclassified and is included in finance expense.

8. Royalties

   Under Previous GAAP, current taxes included Saskatchewan resource surcharge. Under IFRS, Saskatchewan resource surcharge has been deemed a royalty and deducted from petroleum and natural gas revenues.

9. Adjustments to the Consolidated Statement of Cash Flows

   The transition from Previous GAAP to IFRS had no significant impact on cash flows generated by the Corporation. Cash flows related to interest are classified as financing while under Previous GAAP, cash flows relating to interest were classified as operating.

Consolidated Management's Discussion & Analysis

The following Management's Discussion and Analysis ("MD&A"), dated as of March 23, 2012, 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, 2011 and should be read in conjunction with the December 31, 2011 audited consolidated financial statements. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") and all references are to Canadian dollars unless otherwise indicated. The term "boe" or barrels of oil equivalent may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent (6 mcf: 1 bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. 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.

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 prior to the consideration of how these activities are financed or how the results are taxed. Investors should be cautioned that these measures should not be construed as an alternative to net income, comprehensive income, cash provided by operating activities or other measures of financial performance as determined in accordance with GAAP. Advantage's method of calculating these measures may differ from other companies, and accordingly, they may not be comparable to similar measures used by other companies.

Funds from operations, as presented, is based on cash provided by operating activities before expenditures on 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 boe 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)	2011	2010	% change	2011	2010	% change
Cash provided by operating activities	$ 79,932	$ 60,964	31%	$ 218,181	$ 222,866	(2)%
Expenditures on decommissioning liability	761	1,811	(58)%	3,335	6,275	(47)%
Changes in non-cash working capital	(21,922)	(16,468)	33%	(4,131)	(31,008)	(87)%
Finance expense [(1)]	(4,137)	(5,679)	(27)%	(20,354)	(24,832)	(18)%
Funds from operations	**$ 54,634**	**$ 40,628**	**34%**	**$ 197,031**	**$ 173,301**	**14%**

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

Creation of Longview Oil Corp.

On April 14, 2011, Advantage's wholly-owned subsidiary, Longview Oil Corp. ("Longview"), completed its initial public offering (the "Offering") at a price of $10 per common share issuing 17,250,000 common shares and raising gross proceeds of $172.5 million (including full exercise of the over-allotment option on April 28, 2011). Concurrent with the closing of the Offering, Longview purchased certain oil-weighted assets (the "Acquired Assets") from Advantage for total consideration of $546.9 million, comprised of 29,450,000 common shares of Longview representing a 63% equity ownership and $252.4 million in cash (the "Acquisition"). The Acquired Assets were purchased with an effective date of January 1, 2011 and a closing date of April 14, 2011. As Advantage is the parent company and has a majority ownership interest of Longview, the financial and operating results of Longview are consolidated 100% within Advantage and non-controlling interest has been recognized which represents Longview's independent shareholders 37% ownership interest in the net assets and income of Longview. Refer to the MD&A section "Supplementary Financial and Operating information for Advantage and Longview" which provides detailed financial and operational information with respect to the separate legal entities.

As the Acquisition closed on April 14, 2011, financial and operating results from the Acquired Assets belong to Advantage for the period prior to April 14, 2011 and are solely attributed to Advantage's shareholders. For the period from April 14 to December 31, 2011, the financial and operating results from the Acquired Assets belong to Longview and are attributed to Longview's shareholders based on their ownership interests.

Upon closing of the Acquisition, Advantage entered into a Technical Services Agreement (the "TSA") with Longview. Under the TSA, Advantage will provide the necessary personnel and technical services to manage Longview's business and Longview will reimburse Advantage on a monthly basis for its share of administrative charges based on respective levels of production. Longview has an independent board of directors with three initial members. The officers of Longview provide services to Longview under the TSA but remain employees of Advantage.

Supplementary Financial and Operating Information for Advantage and Longview

The following information has been presented to provide additional information with respect to the legal entity financial and operating information for each of Advantage and Longview. As the Acquisition closed on April 14, 2011, financial and operating results from the Acquired Assets belong to Advantage for the period prior to April 14, 2011 and are solely attributed to Advantage's shareholders. For the period from April 14 to December 31, 2011, the financial and operating results from the Acquired Assets belong to Longview and are attributed to Longview's shareholders based on their ownership interests.

	Three months ended December 31, 2011			Year ended December 31, 2011		
	Advantage	**Longview**	**Consolidated**	**Advantage**	**Longview** (1)	**Consolidated**
Production						
Natural gas (mcf/d)	127,265	10,215	137,480	123,246	9,514	130,075
Crude oil (bbls/d)	630	4,552	5,182	1,746	4,131	4,711
NGLs (bbls/d)	748	568	1,316	1,118	559	1,519
Total (boe/d)	**22,589**	**6,823**	**29,411**	**23,405**	**6,276**	**27,909**
Natural gas (%)	94%	25%	78%	88%	25%	78%
Crude oil (%)	3%	67%	18%	7%	66%	17%
NGLs (%)	3%	8%	4%	5%	9%	5%
Natural Gas Prices ($/mcf)						
Realized natural gas prices						
Excluding hedging	$ 3.16	$ 3.47	$ 3.18	$ 3.55	$ 3.81	$ 3.57
Including hedging	$ 3.78	$ 3.47	$ 3.76	$ 4.19	$ 3.81	$ 4.17
Crude Oil and NGLs Prices ($/bbl)						
Realized crude oil prices						
Excluding hedging	$ 91.40	$ 89.05	$ 89.34	$ 85.68	$ 87.81	$ 87.02
Including hedging	$ 91.40	$ 87.37	$ 87.86	$ 82.95	$ 86.81	$ 85.38
Realized NGLs prices						
Excluding hedging	$ 87.23	$ 66.05	$ 78.09	$ 66.31	$ 63.77	$ 65.64
Realized crude oil and NGLs prices						
Excluding hedging	$ 89.14	$ 86.50	$ 87.06	$ 78.12	$ 84.95	$ 81.81
Including hedging	$ 89.14	$ 85.01	$ 85.88	$ 76.45	$ 84.06	$ 80.56
Cash netbacks ($/boe)						
Petroleum and natural gas sales	$ 23.24	$ 70.11	$ 34.11	$ 28.26	$ 69.26	$ 34.88
Royalties	(2.16)	(14.11)	(4.93)	(3.47)	(14.18)	(5.20)
Realized gain (loss) on derivatives	3.49	(1.12)	2.42	3.15	(0.66)	2.54
Operating expense	(4.90)	(18.36)	(8.03)	(6.96)	(18.06)	(8.75)
Operating	**19.67**	**36.52**	**23.57**	**20.98**	**36.36**	**23.47**
General and administrative expense (2)	(2.12)	(1.15)	(1.89)	(2.28)	(1.67)	(2.18)
Finance expense (3)	(1.44)	(1.84)	(1.53)	(2.00)	(2.01)	(2.00)
Miscellaneous income	0.04	-	0.03	0.07	0.01	0.06
Cash netbacks	**$ 16.15**	**$ 33.53**	**$ 20.18**	**$ 16.77**	**$ 32.69**	**$ 19.35**

(1) The year ended December 31, 2011 represents Longview's financial and operating results for the period from April 14 to December 31, 2011.
(2) General and administrative expense excludes non-cash G&A and non-cash share-based compensation expense.
(3) Finance expense excludes non-cash accretion expense.

($000, except as otherwise indicated)	Three months ended December 31, 2011 Advantage	Longview	Consolidated	Year ended December 31, 2011 Advantage	Longview [1]	Consolidated
Sales including realized hedging						
Natural gas sales	$ 36,986	$ 3,263	$ 40,249	$ 159,774	$ 9,500	$ 169,274
Realized hedging gains	7,262	-	7,262	28,657	-	28,657
Natural gas sales including hedging	44,248	3,263	47,511	188,431	9,500	197,931
Crude oil and NGLs sales	11,307	40,744	52,051	81,646	104,368	186,014
Realized hedging losses	-	(704)	(704)	(1,741)	(1,090)	(2,831)
Crude oil and NGLs sales including hedging	11,307	40,040	51,347	79,905	103,278	183,183
Total	**$ 55,555**	**$ 43,303**	**$ 98,858**	**$ 268,336**	**$ 112,778**	**$ 381,114**
per boe	$ 26.73	$ 68.99	$ 36.53	$ 31.41	$ 68.60	$ 37.42
Royalties	$ 4,481	$ 8,858	$ 13,339	$ 29,661	$ 23,310	$ 52,971
per boe	$ 2.16	$ 14.11	$ 4.93	$ 3.47	$ 14.18	$ 5.20
As a percentage of petroleum and natural gas sales	9.3%	20.1%	14.5%	12.3%	20.5%	14.9%
Operating expense	$ 10,191	$ 11,526	$ 21,717	$ 59,473	$ 29,693	$ 89,166
per boe	$ 4.90	$ 18.36	$ 8.03	$ 6.96	$ 18.06	$ 8.75
General and administrative expense [2]	$ 4,400	$ 719	$ 5,119	$ 19,497	$ 2,742	$ 22,239
per boe	$ 2.12	$ 1.15	$ 1.89	$ 2.28	$ 1.67	$ 2.18
Interest on bank indebtedness	$ 989	$ 1,153	$ 2,142	$ 8,173	$ 3,310	$ 11,483
per boe	$ 0.48	$ 1.84	$ 0.79	$ 0.96	$ 2.01	$ 1.13
Interest on convertible debentures	$ 1,995	$ -	$ 1,995	$ 8,871	$ -	$ 8,871
per boe	$ 0.96	$ -	$ 0.74	$ 1.04	$ -	$ 0.87
Miscellaneous income	$ 88	$ -	$ 88	$ 634	$ 13	$ 647
per boe	$ 0.04	$ -	$ 0.03	$ 0.07	$ 0.01	$ 0.06
Funds from operations	**$ 33,587**	**$ 21,047**	**$ 54,634**	**$ 143,295**	**$ 53,736**	**$ 197,031**
per boe	$ 16.15	$ 33.53	$ 20.18	$ 16.77	$ 32.69	$ 19.35
per share [3] [4]	$ 0.20	$ 0.45	$ 0.28	$ 0.87	$ 1.61	$ 1.07
Dividends from Longview (declared by Longview)	**$ 4,417**	**$ (7,012)**	**$ (2,595)**	**$ 11,780**	**$ (18,695)**	**$ (6,915)**
Expenditures on property, plant and equipment	$ 75,572	$ 25,625	$ 101,197	$ 199,217	$ 54,957	$ 254,174
Expenditures on exploration and evaluation assets	1,604	$ 20	1,624	2,930	76	3,006
Total capital spending	**$ 77,176**	**$ 25,645**	**$ 102,821**	**$ 202,147**	**$ 55,033**	**$ 257,180**
Debt and working capital						
Bank indebtedness				$ 142,548	$ 91,355	$ 233,903
Convertible debentures				$ 86,250	$ -	$ 86,250
Working capital deficit				$ 70,564	$ 20,074	$ 90,638

(1) The year ended December 31, 2011 represents Longview's financial and operating results for the period from April 14 to December 31, 2011.
(2) General and administrative expense excludes non-cash G&A and non-cash share-based compensation expense.
(3) Based on basic weighted average shares outstanding applicable to each legal entity.
(4) Consolidated funds from operations per share excludes funds from operations attributable to the non-controlling interest of Longview.

Transition to International Financial Reporting Standards

The consolidated financial statements, MD&A and comparative information have been prepared in accordance with IFRS representing generally accepted accounting principles (“GAAP”) for publicly accountable enterprises in Canada. The transition date to IFRS was January 1, 2010 and comparative figures for 2010 and Advantage’s financial position as at January 1, 2010 have been restated to IFRS from the previous Canadian generally accepted accounting principles (“Previous GAAP”). Reconciliations to IFRS from Previous GAAP financial statements including the impact of the transition on the Corporation's reported financial position and financial performance, and the nature and effect of significant changes in accounting policies from those used in the Corporation’s Previous GAAP consolidated financial statements for the year ended December 31, 2010, are summarized in note 25 to the audited consolidated financial statements.

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, statements with respect to terms of the TSA with Longview; effect of commodity prices on the Corporation's Corporation’s financial condition and performance, including cash provided by operating activities, funds from operations, net income and comprehensive income; industry conditions; effect of commodity prices on sales, drilling activity and supply levels; effect of derivative contracts on sales and cash flows; the Corporation's hedging strategy; effect of the Corporation's risk management activities; expected effect on production from the completion of facilities and infrastructure expansion work in Glacier, Alberta; expected production from the Glacier development; projected royalty rates; average royalty rates; terms of the Plans and the grants of restricted shares; terms of the convertible debentures; the Corporation's estimated tax pools; timing of expiry of federal non-capital loss carry forward; future commitments and contractual obligations; effect of changes in reserves estimates or commodity prices on the borrowing base of the Credit Facilities (as defined herein); terms of the Credit Facilities, including Management's expectations regarding extension of the term of the Credit Facilities; the Corporation's plans for managing its capital structure; the Corporation's ability to satisfy all liabilities and commitments as they come due; our future operating and financial results; supply and demand for oil and natural gas; projections of market prices and costs; effect of natural gas, oil prices and exchange rates on the Corporation's financial performance; the Corporation’s exploration and drilling plans; focus of spending and capital budgets; capital expenditure programs; the focus and anticipated timing of capital expenditures; plans for development of the Middle and Lower Montney; projected average production; anticipated timing of incremental production; expected exit rate production for Longview; the Corporation's business strategy and it plans for its assets; Longview's business strategy; the performance characteristics of our properties; and the amount of general and administrative expenses.

In addition, statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future.

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; competition from other producers; the lack of availability of qualified personnel or management; individual well productivity; ability to access sufficient capital from internal and external sources; credit risk; and the risks and uncertainties are 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, Advantage has made assumptions regarding, but not limited to: conditions in general economic and financial markets; effects of regulation by governmental agencies; 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 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 oil and gas properties in the manner currently contemplated; current or, where applicable, proposed assumed industry conditions, laws and regulations will continue in effect or as anticipated as described herein; and the estimates of the Corporation's production and reserves 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.

Overview

	Three months ended December 31			**Year ended December 31**		
	2011	**2010**	**% change**	**2011**	**2010**	**% change**
Cash provided by operating activities ($000)	$ 79,932	$ 60,964	31%	$ 218,181	$ 222,866	(2)%
Funds from operations ($000)	$ 54,634	$ 40,628	34%	$ 197,031	$ 173,301	14%
per share [(1)]	$ 0.28	$ 0.25	12%	$ 1.07	$ 1.06	1%
per boe	$ 20.18	$ 18.16	11%	$ 19.35	$ 19.67	(2)%

[(1)] Based on basic weighted average shares outstanding and excludes funds from operations attributable to the non-controlling interest of Longview.

Funds from operations for 2011 have been strong, driven by increases in production and continued gains from our hedging program, which demonstrates the clear ongoing improvement in our financial and operating results from our focused development program. Average daily production during the fourth quarter of 2011 increased 21% above the same period of 2010, with a 30% increase in natural gas production and a 6% increase in crude oil production, partially offset by a 24% decrease NGLs production. For the three months ended December 31, 2011, we recognized a net realized derivative gain of $6.6 million and for the year ended December 31, 2011, we recognized a net realized derivative gain of $25.8 million on settled derivative contracts, primarily as a result of lower average actual natural gas prices during the periods as compared to our established average hedge prices. Our successful commodity price risk management program continued to realize significant gains on derivatives during 2011 that has helped to offset the continued weak natural gas prices and positively impact funds from operations. Our net realized derivative gain has decreased during 2011 as compared to 2010 as we had less natural gas production hedged for this year at lower average prices and we have generally realized losses on our crude oil hedges. Funds from operations have also benefited during this year from higher crude oil prices and continued cost reductions, such as operating costs, general and administrative expense, and finance expense. Unfortunately, natural gas prices still remain weak and pose a continuing challenge to the entire natural gas industry. When comparing the current quarter to the third quarter of 2011, our funds from operations increased 9% and funds from operations per boe were 6% higher as realized crude oil and NGL prices increased during this quarter and general costs continued to decrease, including operating costs.

Our financial and operating results during 2011 as compared to 2010 have been partially impacted by dispositions completed during the second quarter of 2010. On May 31 and June 3, 2010, we closed two asset dispositions of non-core natural gas weighted properties for net proceeds of $66.5 million and representing production of approximately 1,700 boe/d. The net proceeds from the various dispositions were utilized to reduce outstanding debt. As a result of the dispositions, total funds from operations was negatively impacted for 2011 as compared to 2010 with all sales and expenses generally impacted.

As a result of asset dispositions completed in 2010 and 2011 and changes in commodity prices, historical financial and operating performance may not be indicative of actual future performance.

The primary factor that causes significant variability of the Corporation's cash provided by operating activities, funds from operations, net income and comprehensive income is commodity prices. Refer to the section "Commodity Prices and Marketing" for a more detailed discussion of commodity prices and our price risk management.

Petroleum, Natural Gas Sales and Hedging

($000)	Three months ended December 31 2011	2010	% change	Year ended December 31 2011	2010	% change
Natural gas sales	$ 40,249	$ 34,081	18%	$ 169,274	$ 146,572	15%
Realized hedging gains	7,262	12,871	(44)%	28,657	55,360	(48)%
Natural gas sales including hedging	47,511	46,952	1%	197,931	201,932	(2)%
Crude oil and NGLs sales	52,051	42,140	24%	186,014	172,796	8%
Realized hedging losses	(704)	(3,080)	(77)%	(2,831)	(10,227)	(72)%
Crude oil and NGLs sales including hedging	51,347	39,060	31%	183,183	162,569	13%
Total (1)	**$ 98,858**	**$ 86,012**	**15%**	**$ 381,114**	**$ 364,501**	**5%**

(1) Total excludes unrealized derivative gains and losses.

Total sales, excluding hedging, increased 21% and 11% for the three months and year ended December 31, 2011 as compared to 2010, respectively. Sales have been positively impacted from significant increases in our production during these periods due to our successful exploration and development activities. Natural gas sales in particular have benefited from our Montney natural gas resource play at Glacier, Alberta where we have increased production capacity with our Phase III facilities and infrastructure expansion work completed in the first quarter of 2011. Crude oil and NGL production has also increased during the fourth quarter of 2011 due to production additions from Longview's capital expenditure program that began late in 2011, delayed by poor field conditions from severe wet weather. The increase in sales during 2011 has been partially offset by reduced production attributable to asset dispositions that closed in the second quarter of 2010. We have also experienced an increase in sales during 2011 due to higher realized crude oil and NGLs prices, excluding hedging. However, sales continues to be adversely impacted by the natural gas price environment that has been weak during the last several years attributable to many factors, including continued high US domestic natural gas production that has increased supply and the ongoing weak North American economy that has negatively impacted demand. These factors, in combination with mild weather conditions, have resulted in historic high inventory levels that are currently well-above the five-year average. This current environment has placed considerable downward pressure on natural gas prices.

Given the low natural gas price environment, our commodity price risk management program has delivered realized natural gas hedging gains of $7.3 million and $28.7 million for the three months and year ended December 31, 2011, respectively. As crude oil prices have remained relatively strong, we realized minor crude oil hedging losses of $0.7 million for the three months and $2.8 million for the year ended December 31, 2011. The Corporation enters derivative contracts whereby realized hedging gains and losses partially offset commodity price fluctuations, which can positively or negatively impact sales. The realized natural gas hedging gains have been significant and helped us stabilize cash flows and ensure that our capital expenditure program is substantially funded by such cash flows. However, we have no natural gas hedges for 2012.

Production

	Three months ended December 31 2011	2010	% change	Year ended December 31 2011	2010	% change
Natural gas (mcf/d)	137,480	106,125	30%	130,075	101,562	28%
Crude oil (bbls/d)	5,182	4,886	6%	4,711	5,076	(7)%
NGLs (bbls/d)	1,316	1,734	(24)%	1,519	2,126	(29)%
Total (boe/d)	**29,411**	**24,308**	**21%**	**27,909**	**24,129**	**16%**
Natural gas (%)	78%	73%		78%	70%	
Crude oil (%)	18%	20%		17%	21%	
NGLs (%)	4%	7%		5%	9%	

Average daily production during the fourth quarter of 2011 increased 21% above the same period of 2010, with a 30% increase in natural gas production and a 6% increase in crude oil production, partially offset by a 24% decrease NGLs production. Production for the current quarter was 3% higher than the 28,638 boe/d reported in the third quarter of 2011. For the year ended December 31, 2011, average daily production increased 16% above the prior year, with a 28% increase in natural gas production and decreases in both crude oil and NGLs production.

Production for 2010 and 2011 has continued to be primarily impacted by Advantage's significant production growth at Glacier, Alberta. During the second quarter of 2010 our 100% working interest gas plant ("Glacier gas plant") was brought on-stream ahead of schedule with production rates exceeding 50 mmcf/d (8,300 boe/d). Due to stronger than expected well performance, we were able to further increase Glacier production exiting 2010 exceeding 60 mmcf/d (10,000 boe/d). Phase III of our Glacier development project was completed during the first quarter of 2011 on-budget and ahead of schedule with production capacity at 100 mmcf/d (16,667 boe/d) resulting in a peak corporate production rate of approximately 30,000 boe/d at March 31, 2011. During the third quarter of 2011, the Glacier gas plant experienced planned facility downtime to complete our acid gas injection system and maintenance work conducted by TransCanada Pipelines ("TCPL"). During the fourth quarter of 2011, we successfully commissioned the acid gas injection system which is now capable of disposing acid gas volumes for plant inlet gas volumes in excess of 140 mmcf/d. In addition, TCPL completed further looping of their sales pipeline lateral in preparation for our plant expansion to 140 mmcf/d. These projects represent significant milestones towards achieving our Glacier Phase IV development and will provide additional flexibility for future production growth. Further plant downtime will be required during the first and second quarters of 2012 to accommodate future equipment installations to finalize the expansion of our Glacier gas plant processing capacity to 140 mmcf/d.

Longview's daily production averaged 6,823 boe/d for the fourth quarter of 2011, an increase of 12% from 6,071 boe/d realized in the third quarter of 2011 with 75% from crude oil and NGLs. During much of the spring and summer, field conditions were poor with severe wet weather that created challenges for the industry to conduct regular well maintenance and sustain production levels. Fortunately, much of Longview's production is pipeline connected rather than trucked and they experienced less outages such that the weather impact was minimal. However, routine well maintenance and their current year capital program were delayed while conditions improved. During the third quarter Longview began to expedite maintenance activities, workovers and reactivations and commenced their 2011 Alberta capital expenditure program in July with the Saskatchewan program beginning in September. The well maintenance and workover activity continued into the fourth quarter and generally lead to higher operating costs during these periods. Production additions from their capital expenditure program began at the end of the third quarter and resulted in their fourth quarter production increasing 12%.

Commodity Prices and Marketing

Natural Gas

($/mcf)	Three months ended December 31 2011	Three months ended December 31 2010	% change	Year ended December 31 2011	Year ended December 31 2010	% change
Realized natural gas prices						
Excluding hedging	$ 3.18	$ 3.49	(9)%	$ 3.57	$ 3.95	(10)%
Including hedging	$ 3.76	$ 4.81	(22)%	$ 4.17	$ 5.45	(23)%
AECO daily index	$ 3.20	$ 3.63	(12)%	$ 3.63	$ 3.99	(9)%

Realized natural gas prices, excluding hedging, for the three months ended December 31, 2011 were 9% lower as compared to the same period of 2010 and decreased 10% for the year ended December 31, 2011 as compared to the prior year. Our realized natural gas prices, excluding hedging, for this quarter were 12% lower than the $3.62/mcf realized during the third quarter of 2011. Although natural gas prices have continued to remain weak, our commodity hedging has resulted in realized natural gas prices, including hedging, that exceeds current market prices and has reduced the volatility of our cash flows. However, realized natural gas prices, including hedging, have decreased more during 2011 as compared to 2010 as we had less natural gas production hedged for this year at lower average prices. We have no natural gas production hedged for 2012.

During 2010 and 2011, natural gas prices have remained low from continued high US domestic natural gas production that has increased supply, particularly from non-conventional natural gas resource plays, and the ongoing weak North American economy that has negatively impacted demand. These factors, in combination with mild weather conditions, have resulted in historic high inventory levels that are currently well-above the five-year average. This current environment has placed considerable downward pressure on natural gas prices with AECO gas presently trading at approximately $1.80/mcf and we anticipate that natural gas prices will remain low in the near term. We continue to believe in the longer-term price support for natural gas due to the increased proportion of resource based natural gas supplies that experience higher initial production declines and reduced conventional natural gas drilling, both of which could eventually lead to a more balanced supply and demand environment. We monitor market developments closely and will be proactive in implementing an appropriate hedging strategy to mitigate the volatility in our cash flow as a result of fluctuations in natural gas prices.

Crude Oil and NGLs

($/bbl)	Three months ended December 31 2011	2010	% change	Year ended December 31 2011	2010	% change
Realized crude oil prices						
Excluding hedging	$ 89.34	$ 74.76	20%	$ 87.02	$ 72.80	20%
Including hedging	$ 87.86	$ 67.91	29%	$ 85.38	$ 67.28	27%
Realized NGLs prices						
Excluding hedging	$ 78.09	$ 53.50	46%	$ 65.64	$ 48.88	34%
Realized crude oil and NGLs prices						
Excluding hedging	$ 87.06	$ 69.19	26%	$ 81.81	$ 65.74	24%
Including hedging	$ 85.88	$ 64.14	34%	$ 80.56	$ 61.85	30%
WTI ($US/bbl)	$ 94.02	$ 85.18	10%	$ 95.14	$ 79.55	20%
$US/$Canadian exchange rate	$ 0.98	$ 0.99	(1)%	$ 1.01	$ 0.97	4%

Realized crude oil and NGLs prices, excluding hedging, increased 26% for the three months ended and 24% for the year ended December 31, 2011, as compared to the same periods of 2010. Realized crude oil and NGLs prices, excluding hedging, have increased 14% for the fourth quarter of 2011 in comparison to the third quarter of 2011. Crude oil and NGL pricing has continued to experience considerable volatility with West Texas Intermediate ("WTI") increasing 5% to US$94.02/bbl as compared to US$89.81/bbl experienced in the third quarter of 2011. Advantage's realized crude oil price may not change to the same extent as WTI due to changes in the $US/$Canadian exchange rate and changes in Canadian crude oil differentials relative to WTI. The price of WTI fluctuates based on worldwide supply and demand fundamentals with significant price volatility experienced over the last several years. WTI had been relatively strong during 2010 and near the end of the year began to increase and significantly escalated during early 2011, primarily influenced by middle-east tensions and associated supply concerns, with WTI currently trading at approximately US$107/bbl. However, we have also seen a general strengthening of the $US/$Canadian exchange rate during these periods that has partially offset the improvement in WTI. We believe that the long-term pricing fundamentals for crude oil will remain strong with supply management by the OPEC cartel and strong relative demand from developing countries.

Commodity Price Risk

The Corporation's financial results and condition will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely and are determined by economic and political factors. Supply and demand factors, including weather and general economic conditions as well as conditions in other oil and natural gas regions, impact prices. Any movement in oil and natural gas prices will have an effect on the Corporation's financial condition and performance. Advantage has an established financial hedging strategy and may manage the risk associated with changes in commodity prices by entering into derivative contracts. Although these commodity price risk management activities could expose Advantage to losses or gains, entering derivative contracts helps us to stabilize cash flows and ensures that our capital expenditure program is substantially funded by such cash flows. To the extent that Advantage engages in risk management activities related to commodity prices, it will 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. Our Credit Facilities also prohibit the Corporation from entering into any derivative contract where the term of such contract exceeds three years. Further, the aggregate of such contracts cannot hedge greater than 60% of total estimated oil and natural gas production over two years and 50% over the third year.

Currently the Corporation has the following derivatives in place:

Description of Derivative	Term	Volume	Average Price
Crude oil – WTI			
Fixed price [1]	January 2012 to December 2012	1,000bbls/d	Cdn $97.10/bbl
Collar [1]	January 2012 to December 2012	1,000bbls/d	Bought put Cdn $90.00/bbl Sold call Cdn $102.25/bbl

(1) These financial contracts were entered by Longview.

A summary of realized and unrealized hedging gains and losses for the three months and years ended December 31, 2011 and 2010 are as follows:

($000)	Three months ended December 31 2011	2010	% change	Year ended December 31 2011	2010	% change
Realized hedging						
Natural gas	$ 7,262	$ 12,871	(44)%	$ 28,657	$ 55,360	(48)%
Crude oil	(704)	(3,080)	(77)%	(2,831)	(10,227)	(72)%
Total realized hedging gains	6,558	9,791	(33)%	25,826	45,133	(43)%
Unrealized hedging						
Natural gas	(6,684)	7,637	(188)%	(25,152)	11,299	(323)%
Crude oil	(3,919)	(21,784)	(82)%	(199)	(5,918)	(97)%
Total unrealized hedging gains (losses)	(10,603)	(14,147)	(25)%	(25,351)	5,381	(571)%
Total gains (losses) on derivatives	**$ (4,045)**	**$ (4,356)**	**(7)%**	**$ 475**	**$ 50,514**	**(99)%**

For the three months ended December 31, 2011, we recognized a net realized derivative gain of $6.6 million (December 31, 2010 - $9.8 million net realized derivative gain) and for the year ended December 31, 2011, we recognized a net realized derivative gain of $25.8 million (December 31, 2010 - $45.1 million net realized derivative gain) on settled derivative contracts, primarily as a result of lower average actual natural gas prices during the periods as compared to our established average hedge prices. Our net realized derivative gain has decreased during 2011 as compared to 2010 as we had less natural gas production hedged for this year at lower average prices and we have generally realized losses on our crude oil hedges. However, our successful commodity price risk management program continued to realize significant gains on derivatives during 2011 that has helped to offset the continued weak natural gas prices and positively impact funds from operations. As at December 31, 2011, the fair value of the derivative contracts outstanding and to be settled was a net liability of approximately $2.7 million, a decrease of $25.3 million from the $22.6 million net asset recognized as at December 31, 2010. For the year ended December 31, 2011, this $25.3 million decrease in the fair value of derivative contracts was recognized in income as an unrealized derivative loss (December 31, 2010 – $5.4 million unrealized derivative gain). The valuation of the derivatives is the estimated fair value to settle the contracts as at December 31, 2011 and is based on pricing models, estimates, assumptions and market data available at that time. As such, the recognized amounts are not cash and the actual gains or losses realized on eventual cash settlement can vary materially due to subsequent fluctuations in commodity prices and foreign exchange rates as compared to the valuation assumptions. The Corporation does not apply hedge accounting and current accounting standards require changes in the fair value to be included in the consolidated statement of comprehensive income as a derivative gain or loss with a corresponding derivative asset and liability recorded on the statement of financial position. These derivative contracts will settle in 2012 corresponding to when the Corporation will recognize sales from production.

Royalties

	Three months ended December 31 2011	2010	% change	Year ended December 31 2011	2010	% change
Royalties ($000)	$ 13,339	$ 9,661	38%	$ 52,971	$ 45,954	15%
per boe	$ 4.93	$ 4.32	14%	$ 5.20	$ 5.22	-%
As a percentage of petroleum and natural gas sales	14.5%	12.7%	1.8%	14.9%	14.4%	0.5%

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. Royalties include payments for Saskatchewan Resource Surcharge which is based on the petroleum and natural gas sales earned within the Province of Saskatchewan. Royalties also include the impact of gas cost allowance ("GCA"), which is a reduction of royalties payable to the Alberta Provincial Government to recognize capital and operating expenditures incurred in the gathering and processing of their share of natural gas production and does not generally fluctuate with natural gas prices. Total royalties paid has increased as compared to the prior year periods mainly due to the higher corporate production. Royalties as a percentage of petroleum and natural gas sales have increased as significant increases in crude oil and NGL prices have more than offset decreases in natural gas prices. The royalty rate realized by each of Advantage and Longview on a stand-alone basis for the current quarter was 9.3% and 20.1%, respectively. Advantage's royalty rates, that are predominately based on natural gas production have decreased due to lower natural gas prices and lower average royalties attributed to production from our significant development at Glacier, Alberta. Longview's royalty rates are higher due to the stronger relative crude oil and NGL prices.

Our average corporate royalty rates are significantly impacted by the Alberta Provincial Government's royalty framework for conventional oil, natural gas and oil sands whereby Alberta royalties are affected by depths, well production rates, and commodity prices. Additionally, the Alberta Provincial Government has a number of drilling incentive programs with reduced royalty rates for qualifying wells. All of our Montney horizontal wells at Glacier drilled after May 1, 2010 qualify for the Alberta Provincial Government's Natural Gas Deep Drilling Program ("NGDDP") which is estimated to provide a royalty incentive of $2.7 to $3.4 million for a typical horizontal well (a typical Advantage horizontal well at Glacier is 4,200 to 4,500 metres in total length). This royalty incentive results in an estimated 5% royalty rate for all Montney horizontal wells for the life of the well. This significantly lowers the natural gas price threshold required to drill economic wells and substantially improves the value of future reserves and upside potential at Glacier. Therefore, corporate royalty rates will continue to fluctuate based on commodity prices, individual well productivity, and our ongoing capital development plans.

Operating Expense

	Three months ended December 31			Year ended December 31		
	2011	**2010**	**% change**	**2011**	**2010**	**% change**
Operating expense ($000)	$ 21,717	$ 23,811	(9)%	$ 89,166	$ 95,609	(7)%
per boe	$ 8.03	$ 10.65	(25)%	$ 8.75	$ 10.86	(19)%

Total operating expense decreased 9% for the three months and 7% for the year ended December 31, 2011 as compared to the same periods of 2010. Operating expense per boe decreased 25% and 19% for the three months and year ended December 31, 2011 as compared to the prior year.

Operating expense per boe realized by Advantage on a stand-alone basis for the fourth quarter of 2011 was $4.90/boe. The reduction in total operating expense has been primarily due to increased production from Glacier, benefits of our ongoing optimization program, the sale of higher cost assets, and a one-time $1.7 million equalization that was recognized in the fourth quarter of 2011 related to a gas processing facility. Operating expense at Glacier is approximately $0.30/mcf ($1.80/boe) at 100 mmcf/d due to the efficiencies created by increasing the production rate through our 100% owned Glacier gas plant.

Operating expense per boe realized by Longview for the current quarter was $18.36/boe. During much of the spring and summer, field conditions were poor with severe wet weather that created challenges for the industry to conduct regular well maintenance and sustain production levels. Therefore, routine well maintenance and Longview's current year capital program were delayed while conditions improved. During the third quarter Longview began to expedite maintenance activities, workovers and reactivations and commenced their 2011 Alberta capital expenditure program in July with the Saskatchewan program beginning in September. The well maintenance and workover activity continued into the fourth quarter and generally lead to higher operating costs during these periods. To mitigate risks associated with fluctuating power costs, Longview has also fixed the price on 0.9 MW at $77.88/MWh for the period from January 2012 to December 2012. Longview anticipates operating costs to be $16.00 to $17.00/boe during 2012.

General and Administrative Expense

	Three months ended December 31			Year ended December 31		
	2011	2010	% change	2011	2010	% change
General and administrative expense						
Cash expense ($000)	$ 5,119	$ 6,197	(17)%	$ 22,239	$ 25,316	(12)%
per boe	$ 1.89	$ 2.77	(32)%	$ 2.18	$ 2.87	(24)%
Non-cash expense ($000)	$ 2,107	$ 2,039	3%	$ 12,348	$ 12,877	(4)%
per boe	$ 0.78	$ 0.91	(14)%	$ 1.21	$ 1.46	(17)%
Total general and administrative expense ($000)	$ 7,226	$ 8,236	(12)%	$ 34,587	$ 38,193	(9)%
per boe	$ 2.67	$ 3.68	(27)%	$ 3.39	$ 4.33	(22)%
Employees at December 31				125	128	(2)%

Cash general and administrative ("G&A") expense for the year ended December 31, 2011 has decreased as compared to 2010 due to ongoing cost reduction efforts, which along with the increased production has reduced cash G&A per boe.

Non-cash G&A expense is comprised of Advantage's and Longview's Restricted Share Performance Incentive Plans ("RSPIP" or the "Plans") with the purpose to retain and attract employees, to reward and encourage performance, and to focus employees on operating and financial performance that results in lasting shareholder returns. The Plans authorize the Boards of Directors to grant restricted shares of each public company to service providers including directors, officers, employees and consultants of Advantage and Longview. The number of restricted shares granted is based on each Corporations' share price return for a twelve-month period and compared to the performance of a peer group approved by the Boards of Directors. The share price returns are calculated at the end of each and every quarter and are primarily based on the twelve-month change in the share prices including dividends. If a share price return for a twelve-month period is positive, a restricted share grant will be calculated based on the return. Otherwise, no restricted shares will be granted to service providers for the period. If the share price return for a twelve-month period is negative, but the return is still within the top two-thirds of the approved peer group performance, the Board of Directors may grant a discretionary restricted share award. Restricted shares vest one-third immediately on grant date with the remaining two-thirds vesting on each of the subsequent two anniversary dates. On vesting, common shares are issued to the service providers in exchange for their restricted shares outstanding. Compensation cost related to the Plans are recognized as share-based compensation expense within G&A expense over the service periods of the service providers and incorporates the fair value at grant date, the estimated number of restricted shares to vest, and certain management estimates.

For the year ended December 31, 2011, Advantage granted 1,443,956 restricted shares at an average grant price of $7.78 per restricted share and recognized $11.5 million of share-based compensation expense as non-cash G&A expense. During the year ended December 31, 2011 Advantage issued 2,212,031 common shares to service providers in accordance with the vesting provisions of the RSPIP. As at December 31, 2011, 2,117,710 restricted shares remain unvested and will vest to service providers over the next two years with a total of $5.0 million in compensation cost to be recognized over the future service periods.

For the year ended December 31, 2011, Longview granted 150,722 restricted shares at a grant price of $11.45 per restricted share and recognized $0.8 million of share-based compensation expense as non-cash G&A expense. During the year ended December 31, 2011 Longview issued 50,422 common shares to service providers in accordance with the vesting provisions of the RSPIP. As at December 31, 2011, 100,300 restricted shares remain unvested and will vest to service providers over the next two years with a total of $0.7 million in compensation cost to be recognized over the future service periods.

Depreciation Expense

	Three months ended December 31			Year ended December 31		
	2011	2010	% change	2011	2010	% change
Depreciation expense ($000)	$ 41,669	$ 32,507	28%	$ 152,927	$ 124,592	23%
per boe	$ 15.40	$ 14.54	6%	$ 15.01	$ 14.15	6%

Depreciation of oil and gas properties is provided on the unit-of–production method based on total proved and probable reserves, including future development costs, on a component basis. Depreciation expense has increased for the three months and year ended

December 31, 2011 as compared to 2010 due to the increase in production and a higher average rate of depreciation per boe. The rate of depreciation per boe is higher partially due to an increase in property, plant and equipment attributable to changes in our decommissioning liability. Decommissioning liabilities are determined by discounting at a risk-free rate the expected future cash flows required to decommission all well sites, gathering systems and processing facilities. With the continued decrease in risk-free rates, the net present value of the decommissioning liability has increased with a corresponding increase in property, plant and equipment which impacts our depreciation expense.

Impairment of Oil and Gas Properties

	Three months ended December 31			Year ended December 31		
	2011	**2010**	**% change**	**2011**	**2010**	**% change**
Impairment of oil and gas properties ($000)	$ 187,684	$ 17,500	972%	$ 187,684	$ 17,500	972%

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. 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”). When management judges that circumstances clearly indicate impairment, CGUs are tested for impairment by comparing the carrying values to their recoverable amounts. 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 (refer to the section “Critical Accounting Estimates”). Impairment losses on CGUs are recognized in the Statement of Comprehensive Income as impairment of oil and gas properties and are separately disclosed.

As at December 31, 2011, Advantage determined that the significant reduction in natural gas prices recognized within our year-end independent reserves evaluation was an indicator of impairment. As a result, we completed an impairment assessment and calculated an estimated recoverable amount for our natural gas concentrated CGUs, primarily based upon the net present value after tax of our year-end proved plus probable reserves discounted at 10% and adjusted for a number of other estimates and assumptions. Based upon these calculations, we recognized an impairment loss of $187.7 million related to two CGUs that consist of conventional natural gas focused properties located in Western and Eastern Alberta that had suffered a significant deterioration in value due to the challenging natural gas price environment. No impairment losses were recognized for any other CGUs, including our Glacier property. An impairment loss is reversed if there is subsequently an objective change in the estimates used to determine the recoverable amount.

Exploration and Evaluation Expense

	Three months ended December 31			Year ended December 31		
	2011	**2010**	**% change**	**2011**	**2010**	**% change**
Exploration and evaluation expense ($000)	$ 1,708	$ 752	127%	$ 3,055	$ 752	306%

All exploratory costs incurred subsequent to acquiring the right to explore for oil and natural gas are capitalized as exploration and evaluation assets pending determination of technical feasibility and commercial viability. Such costs can typically include costs to acquire land rights in areas with no proved or probable reserves assigned, geological and geophysical costs, and exploration wells. If the assets are subsequently determined to be technically feasible and commercially viable, the exploratory costs are tested for impairment and then reclassified from exploration and evaluation assets to development and production assets. If exploratory costs are determined not to be technically feasible and commercially viable, the costs are expensed as exploration and evaluation expense. For the year ended December 31, 2011, we expensed exploration and evaluation costs of $3.1 million related to undeveloped land that expired during the period.

Other Income

($000)	Three months ended December 31 2011	2010	% change	Year ended December 31 2011	2010	% change
Gain (loss) on sale of property, plant and equipment	$ 153	$ (1,541)	(110)%	$ 1,325	$ 45,631	(97)%
Miscellaneous income (expense)	88	(36)	(344)%	647	511	27%
	$ 241	$ (1,577)	(115)%	$ 1,972	$ 46,142	(96)%

Other income primarily consists of gains related to the disposition of property, plant and equipment. During 2010, Advantage disposed of several non-core properties and recognized a $45.6 million net gain. For 2011, Advantage disposed of several minor non-core properties and recognized a $1.3 million net gain.

Interest on Bank Indebtedness

	Three months ended December 31 2011	2010	% change	Year ended December 31 2011	2010	% change
Interest on bank indebtedness ($000)	$ 2,142	$ 3,376	(37)%	$ 11,483	$ 13,346	(14)%
per boe	$ 0.79	$ 1.51	(48)%	$ 1.13	$ 1.52	(26)%
Average effective interest rate	5.4%	4.9%	0.5%	5.3%	5.0%	0.3%
Bank indebtedness at December 31 ($000)				233,903	290,657	(20)%

Total interest on bank indebtedness has decreased during 2011 as compared to 2010 primarily due to the reduction in the average debt balance attributable to raising cash proceeds from selling a 37% non-controlling interest in Longview. However, our bank indebtedness has increased $81.5 million during the fourth quarter of 2011 in comparison to the prior quarter due to the maturity and settlement of our 7.75% and 8.00% convertible debentures in December 2011 for $62.3 million in cash and escalation of our capital expenditure programs that modestly exceeded funds from operations. Consolidated bank indebtedness outstanding at the end of December 31, 2011 was $233.9 million consisting of $142.5 million and $91.4 million for each of the legal entities Advantage and Longview, respectively. Advantage's consolidated Credit Facilities of $475 million at December 31, 2011 includes $275 million with Advantage and $200 million with Longview. The Corporation's interest rates are primarily based on short term bankers acceptance rates plus a stamping fee. 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.

Interest and Accretion on Convertible Debentures

	Three months ended December 31 2011	2010	% change	Year ended December 31 2011	2010	% change
Interest on convertible debentures ($000)	$ 1,995	$ 2,303	(13)%	$ 8,871	$ 11,486	(23)%
per boe	$ 0.74	$ 1.03	(28)%	$ 0.87	$ 1.30	(33)%
Accretion on convertible debentures ($000)	$ 824	$ 824	-%	$ 3,360	$ 3,263	3%
per boe	$ 0.30	$ 0.37	(19)%	$ 0.33	$ 0.37	(11)%
Convertible debentures maturity value at December 31 ($000)				$ 86,250	$ 148,544	(42)%

Interest on convertible debentures for 2011 has decreased compared to 2010 due to the maturity and settlement of the 6.50% debentures in June 2010 and the 7.75% and 8.00% convertible debentures in December 2011. Accretion on convertible debentures has remained relatively comparable for the periods.

Accretion on Decommissioning Liability

	Three months ended December 31			Year ended December 31		
	2011	2010	% change	2011	2010	% change
Accretion on decommissioning liability ($000)	$ 1,459	$ 1,270	15%	$ 5,748	$ 6,094	(6)%
per boe	$ 0.54	$ 0.57	(5)%	$ 0.56	$ 0.69	(19)%
Decommissioning liability at December 31 ($000)				$ 253,796	$ 172,130	47%

Decommissioning liabilities are determined by discounting at a risk-free rate the expected future cash flows required to decommission all petroleum and natural gas assets. With the continued decrease in risk-free rates, the net present value of the decommissioning liability has increased with a corresponding increase in property, plant and equipment. Accretion on decommissioning liability represents the increase in the decommissioning liability each reporting period due to the passage of time and is currently calculated at an annualized rate of 2.5% of the liability. Accretion expense has decreased slightly for 2011 primarily due to a lower annualized rate of accretion.

Taxes

Deferred income taxes arise from differences between the accounting and tax bases of our assets and liabilities. For the year ended December 31, 2011, the Corporation recognized a deferred income tax recovery of $46.8 million compared to a deferred income tax expense of $18.1 million for 2010. The deferred income tax recovery was incurred due to the significant loss before income taxes that was recognized during 2011. As at December 31, 2011, the Corporation had a deferred income tax asset balance of $39.4 million and a deferred income tax liability balance of $29.7 million compared to a net deferred income tax liability balance of $40.2 million at December 31, 2010.

Advantage and Longview have approximately $1.6 billion in tax pools and deductions at December 31, 2011, which can be used to reduce the amount of taxes payable. The estimated tax pools in place are as follows:

	Estimated Tax Pools December 31, 2011 ($ millions)		
	Advantage	Longview	Consolidated
Canadian Development Expenses	$ 106	$ 35	$ 141
Canadian Exploration Expenses	71	-	71
Canadian Oil and Gas Property Expenses	-	367	367
Non-capital losses	631	73	704
Undepreciated Capital Cost	271	76	347
Other	6	8	14
	$ 1,085	**$ 559**	**$ 1,644**

Advantage has a federal non-capital loss carry forward balance of approximately $631 million that will expire between 2024 and 2031. Longview has a federal non-capital loss carry forward balance of approximately $73 million that will expire in 2031 and 2032.

Net Income Attributable to Non-Controlling Interest

At December 31, 2011, Advantage had a 63% ownership interest in Longview with the remaining 37% held by outside interests or non-controlling interests. As Advantage is the parent company and has a majority ownership interest of Longview, Advantage's consolidated financial statements include 100% of Longview's accounts. To determine the net income attributable to the Advantage shareholders, it is necessary to deduct that portion of the net income related to Longview that is consolidated within Advantage's financial results but are attributable to the 37% non-controlling interest. Therefore, for the year ended December 31, 2011, Advantage recognized a $7.4 million reduction to net income related to Longview's net income attributable to the non-controlling interests.

Net Income (Loss) and Comprehensive Income (Loss)

	Three months ended December 31 2011	Three months ended December 31 2010	% change	Year ended December 31 2011	Year ended December 31 2010	% change
Net income (loss) and comprehensive income (loss) ($000)	$ (145,063)	$ (22,888)	534%	$ (152,772)	$ 40,920	(473)%
per share - basic	$ (0.87)	$ (0.14)	521%	$ (0.92)	$ 0.25	(468)%
- diluted	$ (0.87)	$ (0.14)	521%	$ (0.92)	$ 0.25	(468)%

The net loss and net loss per common share realized for the year ended December 31, 2011 was a considerable decrease as compared to the net income and net income per common share for 2010. Although Advantage experienced strong operating results that have contributed significantly to our 2011 financial results including production and sales increases, significant realized hedging gains and continued cost reductions, we also experienced an increase in depreciation expense and a significant impairment that resulted in our net loss. Additionally, net income for 2010 was much higher primarily due to significant gains on derivatives and asset dispositions.

Depreciation expense has increased for 2011 as compared to 2010 due to the increase in production and a higher average rate of depreciation per boe. The rate of depreciation per boe is higher partially due to an increase in property, plant and equipment attributable to changes in our decommissioning liability. As at December 31, 2011, Advantage determined that the significant reduction in natural gas prices recognized within our year-end independent reserves evaluation was an indicator of impairment. As a result, we completed an impairment assessment and calculated an estimated recoverable amount for our natural gas concentrated CGUs. Based upon these calculations, we recognized an impairment loss of $187.7 million related to two CGUs that consist of conventional natural gas focused properties located in Western and Eastern Alberta that had suffered a significant deterioration in value due to the challenging natural gas price environment. The derivative gains recognized include both realized and unrealized amounts. Our net derivative gain has decreased during 2011 as compared to 2010 as we had less natural gas production hedged for this year at lower average prices and we have generally realized losses on our crude oil hedges. During 2010 Advantage also disposed of several non-core properties and recognized a net $45.6 million gain.

Cash Netbacks

	Three months ended December 31 2011 $000	2011 per boe	2010 $000	2010 per boe	Year ended December 31 2011 $000	2011 per boe	2010 $000	2010 per boe
Petroleum and natural gas sales	$ 92,300	$ 34.11	$ 76,221	$ 34.08	$ 355,288	$ 34.88	$ 319,368	$ 36.26
Royalties	(13,339)	(4.93)	(9,661)	(4.32)	(52,971)	(5.20)	(45,954)	(5.22)
Realized gain on derivatives	6,558	2.42	9,791	4.38	25,826	2.54	45,133	5.12
Operating expense	(21,717)	(8.03)	(23,811)	(10.65)	(89,166)	(8.75)	(95,609)	(10.86)
Operating	**63,802**	**23.57**	**52,540**	**23.49**	**238,977**	**23.47**	**222,938**	**25.30**
General and administrative (1)	(5,119)	(1.89)	(6,197)	(2.77)	(22,239)	(2.18)	(25,316)	(2.87)
Finance expense (2)	(4,137)	(1.53)	(5,679)	(2.54)	(20,354)	(2.00)	(24,832)	(2.82)
Miscellaneous income	88	0.03	(36)	(0.02)	647	0.06	511	0.06
Funds from operations and cash netbacks	**$ 54,634**	**$ 20.18**	**$ 40,628**	**$ 18.16**	**$ 197,031**	**$ 19.35**	**$ 173,301**	**$ 19.67**

(1) General and administrative expense excludes non-cash G&A and non-cash share-based compensation expense.
(2) Finance expense excludes non-cash accretion expense.

Funds from operations for 2011 have been strong, driven by increases in production and continued gains from our hedging program, which demonstrates the clear ongoing improvement in our financial and operating results from our focused development program. Average daily production during the fourth quarter of 2011 increased 21% above the same period of 2010, with a 30% increase in natural gas production and a 6% increase in crude oil production, partially offset by a 24% decrease in NGL production. Production increases have been primarily due to completion of the Glacier gas plant Phase III expansion to a production capacity of 100 mmcf/d (16,667 boe/d) at the end of the first quarter of 2011. For the three months and year ended December 31, 2011 we realized gains on derivatives of $6.6 million and $25.8 million, respectively. Our hedging program has helped to offset the continued weak natural gas prices and positively impacts funds from operations. However, hedging gains for 2011 have been lower than 2010 as we have a lower percentage of natural gas production hedged at lower average prices. Funds from operations have also benefited during this year from higher crude oil prices and continued cost reductions, such as operating costs, general and administrative expense, and finance expense. Operating costs per boe have significantly decreased as we continue to realize benefits from the addition of lower cost production due to the completion of our Glacier gas plant and our divestment of higher cost assets. We also recognized a one-time $1.7 million equalization in the fourth quarter of 2011 related to a gas processing facility. Finance expense has been reduced as we utilized proceeds from the asset dispositions and disposing of a non-controlling interest in Longview to repay bank indebtedness and maturing convertible debentures. Although funds from operations has also benefited during this year from higher crude oil prices, natural gas prices still remain weak and pose a continuing challenge to the entire natural gas industry. When comparing the current quarter to the third quarter of 2011, our funds from operations increased 9% and funds from operations per boe were 6% higher as realized crude oil and NGL prices increased during this quarter and general costs continued to decrease, including operating costs.

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**	**2012**	**2013**	**2014**	**2015**
Building leases		$ 7.4	$ 3.4	$ 2.5	$ 1.5	$ -
Pipeline/transportation		36.6	12.1	11.9	10.4	2.2
Bank indebtedness (1)	- principal	233.9	-	233.9	-	-
	- interest	18.3	12.4	5.9	-	-
Convertible debentures (2)	- principal	86.2	-	-	-	86.2
	- interest	15.1	4.3	4.3	4.3	2.2
Total contractual obligations		**$ 397.5**	**$ 32.2**	**$ 258.5**	**$ 16.2**	**$ 90.6**

(1) The Corporation's bank indebtedness does not have specific maturity dates. It is governed by credit facility agreements with a syndicate of financial institutions. Under the terms of the agreements, the facilities are reviewed annually, with the next reviews scheduled in April and June 2012. The facilities are revolving, and 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.

(2) As at December 31, 2011, Advantage had $86.2 million convertible debentures outstanding. The convertible debentures are convertible to common shares based on an established conversion price. All remaining obligations related to convertible debentures can be settled through the payment of cash or issuance of common shares at Advantage's option.

Liquidity and Capital Resources

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

	December 31, 2011		
($000, except as otherwise indicated)	**Advantage**	**Longview**	**Consolidated**
Bank indebtedness (non-current)	$ 142,548	$ 91,355	$ 233,903
Working capital deficit (1)	70,564	20,074	90,638
Net debt	213,112	111,429	324,541
Convertible debentures maturity value (non-current)	86,250	-	86,250
Total debt	**$ 299,362**	**$ 111,429**	**$ 410,791**
Shares outstanding	166,304,040	46,750,432	
Shares closing market price ($/share)	$ 4.24	$ 10.12	
Market capitalization (2)	**$ 705,129**	**$ 473,114**	

(1) Working capital deficit is a non-GAAP measure that includes trade and other receivables, prepaid expenses and deposits, trade and other accrued liabilities, and the current portion of other liability
(2) Market capitalization is a non-GAAP measure calculated by multiplying shares outstanding by the closing market share price on the applicable date for each legal entity.

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 liabilities), 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, implementing a dividend reinvestment plan, adjusting capital spending, or disposing of assets or its ownership interest in Longview. 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. The forecast of the Corporation's future cash flows is based on estimates of production, commodity prices, forecast capital and operating expenditures, and other investing and financing activities. The forecast is regularly updated based on new commodity prices and other changes, which the Corporation views as critical in the current environment. 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.

The economic situation during the last several years has created significant commodity price volatility. Natural gas prices have remained low for several years from continued high US domestic natural gas production that has increased supply and the ongoing weak North American economy that has negatively impacted demand. These factors, in combination with mild weather conditions, have resulted in historic high inventory levels and AECO gas is presently trading at approximately $1.80/mcf. However, crude oil prices have generally remained relatively strong, primarily influenced by middle-east tensions and associated supply concerns, with WTI currently trading at approximately US$107/bbl. The outlook for the Corporation from a prolonged weak commodity price environment, particularly natural gas, would be reductions in operating netbacks, funds from operations and capital expenditures. In order to strengthen our financial position and balance our cash flows, in 2010 we completed two non-core asset dispositions and on April 14, 2011 we closed the sale of a 37% non-controlling interest in Longview with the net proceeds utilized to further repay bank indebtedness. These steps have allowed us to repay significant bank indebtedness and maturing convertible debentures and also enabled us to focus capital spending on our Glacier Montney natural gas resource play. However, we continue to be very cognizant of improving our financial flexibility in the current environment.

We believe that Advantage has implemented strategies to protect our business as much as possible in the current industry and economic environment. We have implemented a strategy to substantially balance funds from operations and our capital program expenditure requirements. Historically we have had a successful hedging program that helped to reduce the volatility of funds from operations. However, we have no natural gas hedges for 2012 and are exposed to risks as a result of the current economic situation. We continue to closely monitor the possible impact on our business and strategy, and will make adjustments as necessary with prudent management.

Shareholders’ Equity and Convertible Debentures

Advantage has utilized a combination of equity, convertible debentures and bank debt to finance acquisitions and development activities.

As at December 31, 2011, Advantage had 166.3 million common shares outstanding. During 2011 Advantage issued 2,212,031 common shares to employees in accordance with the vesting provisions of the RSPIP. As at March 23, 2012, common shares outstanding have increased to 166.6 million.

The Corporation had $86.2 million convertible debentures outstanding at December 31, 2011 that were immediately convertible to 10.0 million common shares based on the applicable conversion price (December 31, 2010 - $148.5 million outstanding and convertible to 13.0 million common shares). During the year ended December 31, 2011, there were no conversions of debentures. The principal amounts of the 7.75% and 8.00% convertible debentures matured in December 2011 and were settled with $62.3 million in cash. We have $86.2 million of 5.00% debentures outstanding that mature in January 2015. Our convertible debenture obligation can be settled through the payment of cash or issuance of common shares at Advantage’s option.

Bank Indebtedness, Credit Facilities and Other Obligations

At December 31, 2011, Advantage had consolidated bank indebtedness outstanding of $233.9 million consisting of $142.5 million and $91.4 million for each of the legal entities Advantage and Longview, respectively. Bank indebtedness has decreased $56.8 million since December 31, 2010, primarily due to net proceeds received from the sale of a 37% non-controlling interest in Longview, partially offset by the maturity and settlement of convertible debentures and capital expenditures to complete our Phase III and to commence our Phase IV development programs at Glacier. Advantage’s consolidated credit facilities of $475 million at December 31, 2011 include $275 million with Advantage and $200 million with Longview (the “Credit Facilities”). The credit facilities are each collateralized by a $1 billion floating charge demand debenture covering all assets of the legal entities. As well, the borrowing bases for the credit facilities are determined through utilizing the legal entities regular reserve estimates. The banking syndicate thoroughly evaluates the reserve estimates based upon their own commodity price expectations to determine the amount of the borrowing bases. Revisions or changes in the reserve estimates and commodity prices can have either a positive or a negative impact on the borrowing bases. As a result of the disposition of a non-controlling interest in Longview that closed on April 14, 2011, the Advantage credit facility was reduced to $275 million and Longview’s credit facility was established at $200 million. The next annual reviews are scheduled to occur in April and June 2012. There can be no assurance that the credit facilities will be renewed at the current borrowing base levels at that time.

Advantage had a consolidated working capital deficiency of $90.6 million as at December 31, 2011. Our working capital includes items expected for normal operations such as trade receivables, prepaids, deposits, 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 deficiency is usually higher during the winter months, as would be expected, due to accounts payable and accrued liabilities associated with our active capital expenditure program. We do not anticipate any problems in meeting future obligations as they become due given the level of our funds from operations and undrawn Credit Facilities. It is also important to note that working capital is effectively integrated with Advantage’s revolving operating loan facility, which assists with the timing of cash flows as required.

Non-Controlling Interest

On April 14, 2011, Longview completed its initial public offering at a price of $10 per common share issuing 17,250,000 common shares and raising gross proceeds of $172.5 million (including full exercise of the over-allotment option on April 28, 2011). Concurrent with the closing of the Offering, Longview purchased the Acquired Assets from Advantage for total consideration of $546.9 million, comprised of 29,450,000 common shares of Longview representing a 63% equity ownership and $252.4 million in cash. The remaining 37% equity ownership of Longview is held by outside interests or non-controlling interests. As Advantage is the parent company and has a majority ownership interest of Longview, Advantage’s consolidated financial statements include 100% of Longview’s accounts. On closing of the Acquisition, non-controlling interest of $106.1 million was recognized which represents Longview’s independent shareholders 37% ownership interest in the net assets of Longview. Non-controlling interest on the statement of financial position is continually adjusted for the independent shareholders’ share of Longview’s net income that is consolidated within Advantage’s financial results and reduced for any dividends paid by Longview to the independent shareholders. Therefore, for the year ended December 31, 2011, Advantage recognized a $7.4 million reduction to net income related to Longview’s net income attributable to the non-controlling interests. This $7.4 million increased non-controlling interest on the statement of financial position with a decrease of $6.9 million related to dividends declared by Longview to the non-controlling interest ownership.

Capital Expenditures

($000)	Three months ended December 31 2011	Three months ended December 31 2010	Year ended December 31 2011	Year ended December 31 2010
Drilling, completions and workovers	$ 85,061	$ 55,578	$ 199,170	$ 169,769
Well equipping and facilities	15,984	11,896	52,857	48,782
Land and seismic	138	458	1,704	2,729
Other	14	97	443	403
Expenditures on property, plant and equipment	101,197	68,029	254,174	221,683
Expenditures on exploration and evaluation assets	1,624	529	3,006	2,091
Proceeds from property disposition	(114)	(226)	(1,099)	(69,676)
Net capital expenditures (1)	**$ 102,707**	**$ 68,332**	**$ 256,081**	**$ 154,098**

(1) Net capital expenditures excludes changes in non-cash working capital and change in decommissioning liability.

Advantage's preference is to operate a high percentage of properties such that we can maintain control of capital expenditures, operations and cash flows. Advantage's business structure has been established in order to fully capitalize on both natural gas and crude oil exploration and development opportunities. Advantage is focused primarily on developing the significant natural gas resource play at Glacier, Alberta while retaining a significant investment in Longview that is focused on oil and natural gas liquids production and development.

Advantage on a legal entity basis spent a net $202.1 million on property, plant and equipment and exploration and evaluation assets for the year ended December 31, 2011, including $178.6 million at Glacier, $4.0 million at Brazeau, $4.0 million in Saskatchewan, $3.0 million at Nevis, $3.0 million at Westerose and the remaining balance at other areas. Capital spending projects at Brazeau, Saskatchewan, Nevis and Westerose were incurred by Advantage in preparation for the eventual disposition of the properties to Longview that closed on April 14, 2011. However, Advantage continues to focus on development of our Montney natural gas resource play at Glacier where we will continue to employ a phased development approach. Our Phase III expansion began at the end of the second quarter of 2010 and finished in the second quarter of 2011, including the drilling of 28 horizontal wells (100% working interest) and the fabrication of a new processing train to facilitate expansion of our Glacier gas plant to its current capacity of 100 mmcf/d. In July 2011, the Board of Directors of Advantage approved a capital and operating budget for the twelve month period ending June 30, 2012 of $216 million of which $200 million (93%) is allocated to Glacier. The capital budget is focused on a Phase IV development program at Glacier with two key objectives: i) increase throughput capacity at our Glacier gas plant from 100 mmcf/d to 140 mmcf/d by the second quarter of 2012; and ii) further evaluate the Middle and Lower Montney formations. During much of the spring and summer, field conditions were poor with severe wet weather that created challenges for the industry and our Glacier Phase IV capital program was delayed by approximately 1½ months while conditions improved. As at December 31, 2011, Advantage had three drilling rigs contracted and had drilled 18 wells of our Phase IV program with 3 wells drilling at year-end and subsequently rig released. Completion of our Phase IV wells has begun and 8 wells were completed and tested by year-end. In October 2011, we successfully commissioned the acid gas injection system which is now capable of disposing acid gas volumes for plant inlet gas volumes in excess of 140 mmcf/d. In addition, TCPL completed further looping of their sales pipeline lateral in preparation for our expansion to 140 mmcf/d. These projects represent significant milestones towards achieving our Glacier Phase IV development and will provide additional flexibility for future production growth.

Longview's 2011 capital budget was 100% focused on oil or oil with liquids rich solution gas projects. The majority of their 2011 capital program was completed during the third and fourth quarters of 2011 due to the wet ground conditions that hampered activities in the spring and summer. For the period from April 14 to December 31, 2011, Longview spent a net $55.0 million on property, plant and equipment and exploration and evaluation assets which included $15.1 million at Nevis, $13.5 million at Brazeau, $7.1 million at Westerose, $5.7 million at Steelman, $4.3 million at Sunset, and $4.0 million at Midale with the remaining spending for miscellaneous projects. Longview deployed two drilling rigs in Alberta and an additional rig targeting the Midale formation in southeast Saskatchewan. As of December 31, 2011, they drilled 20.7 net (30 gross) oil wells (100% success rate). During the third and fourth quarters Longview conducted maintenance activities, workovers and reactivations that had been delayed due to poor field conditions. This activity positively impacted production for the fourth quarter of 2011 that average 6,823 boe/d, an increase of 12% as compared to the prior quarter.

Sources and Uses of Funds

The following table summarizes the various funding requirements during the years ended December 31, 2011 and 2010 and the sources of funding to meet those requirements:

($000)	Year ended December 31 2011	2010
Sources of funds		
Funds from operations	$ 197,031	$ 173,301
Proceeds from change in ownership of Longview	160,757	-
Change in non-cash working capital and other	27,659	17,979
Property dispositions	1,099	69,676
Increase in bank indebtedness	-	40,395
	$ 386,546	**$ 301,351**
Uses of funds		
Expenditures on property, plant and equipment	$ 254,174	$ 221,683
Convertible debenture maturities	62,294	69,927
Decrease in bank indebtedness	56,754	-
Dividends declared by Longview to non-controlling interest	6,915	-
Expenditures on decommissioning liability	3,335	6,275
Expenditures on exploration and evaluation assets	3,006	2,091
Reduction of capital lease obligations	68	1,375
	$ 386,546	**$ 301,351**

Advantage has historically focused on balancing our funds from operations and expenditures, particularly property, plant and equipment, to maintain a strong financial position and preserve financial flexibility. Funds from operations for 2011 have been strong, driven by increases in production and continued gains from our hedging program, which demonstrates the clear ongoing improvement in our financial and operating results from our focused development program. For the year ended December 31, 2011, average daily production increased 16% above the prior year, with a 28% increase in natural gas production partially offset by decreases in both crude oil and NGLs production. For the year ended December 31, 2011, we recognized a net realized derivative gain of $25.8 million on settled derivative contracts, primarily as a result of lower average actual natural gas prices during the year as compared to our established average hedge prices. Our successful commodity price risk management program continued to realize significant gains on derivatives during 2011 that has helped to offset the continued weak natural gas prices and positively impact funds from operations. Our net realized derivative gain has decreased during 2011 as compared to 2010 as we had less natural gas production hedged for this year at lower average prices and we have generally realized losses on our crude oil hedges. Funds from operations have also benefited during this year from higher crude oil prices and continued cost reductions, such as operating costs, general and administrative expense, and finance expense. Unfortunately, natural gas prices still remain weak and pose a continuing challenge to the entire natural gas industry. During the second quarter of 2011 Advantage disposed of a 37% non-controlling interest in Longview thereby raising net cash proceeds that significantly reduced bank indebtedness. In December 2011 the principal amounts of the 7.75% and 8.00% convertible debentures matured and were settled with $62.3 million in cash.

Annual Financial Information

The following is a summary of selected financial information of the Corporation for the years indicated.

	Year ended Dec. 31, 2011	Year ended Dec. 31, 2010	Year ended Dec. 31, 2009 [3]
Total sales (before royalties) ($000)	$ 355,288	$ 319,368	$ 343,005
Net income (loss) ($000)	$ (152,772)	$ 40,920	$ (86,426)
per share - basic and diluted	$ (0.92)	$ 0.25	$ (0.56)
Total assets ($000)	$ 1,972,789	$ 1,965,945	$ 1,927,241
Long term financial liabilities ($000) [1]	$ 308,574	$ 363,675	$ 384,700
Distributions declared per Trust Unit [2]	$ -	$ -	$ 0.08

(1) Long term financial liabilities exclude decommissioning liability and deferred income tax liability.
(2) On March 18, 2009 Advantage annouced the discontinuance of distributions.
(3) Total sales (before royalties) and net loss for 2009 were prepared in accordance with the previous Canadian generally accepted accounting principles.

Total sales (before royalties) decreased from 2009 to 2010 due to lower natural gas prices and corporate production. The decrease in production was primarily attributable to significant non-core asset dispositions completed during both 2009 and 2010, with the net proceeds from such dispositions utilized to reduce outstanding bank indebtedness. Sales (before royalties) have increased during 2011 primarily from significant increases in our production due to our successful exploration and development activities. Natural gas sales in particular have benefited from our Montney natural gas resource play at Glacier, Alberta where we have increased production capacity with our continued facilities and infrastructure expansion work. However, the low natural gas prices that have persisted during these years have contributed to the recognized net losses. During 2010 Advantage disposed of several non-core properties during the year and recognized a $45.6 million net gain which resulted in the reported net income. Our net loss for 2011 was considerable as Advantage determined that the significant reduction in natural gas prices recognized within our year-end independent reserves evaluation was an indicator of impairment. As a result, we completed an impairment assessment and calculated an estimated recoverable amount for our natural gas concentrated CGUs. Based upon these calculations, we recognized an impairment loss of $187.7 million related to two CGUs that consist of conventional natural gas focused properties located in Western and Eastern Alberta that had suffered a significant deterioration in value due to the challenging natural gas price environment. Total assets have continually decreased from 2009 through 2011 due to the asset dispositions, depreciation expense and impairment losses that have exceeded capital expenditure activity. From 2009 to 2011 we have also experienced significant decreases in long term financial liabilities due to our concerted efforts to reduce debt, including utilizing net proceeds from significant asset dispositions, an equity financing, and a convertible debenture issuance. We also suspended all distributions in March 2009 and completed our conversion from an income trust to a corporation in July 2009.

Quarterly Performance

($000, except as otherwise indicated)	2011 Q4	2011 Q3	2011 Q2	2011 Q1	2010 Q4	2010 Q3	2010 Q2	2010 Q1
Daily production								
Natural gas (mcf/d)	137,480	134,353	136,986	111,145	106,125	104,714	107,821	87,346
Crude oil and NGLs (bbls/d)	6,498	6,246	5,919	6,251	6,620	6,835	7,395	7,975
Total (boe/d)	29,411	28,638	28,750	24,775	24,308	24,287	25,365	22,533
Average prices								
Natural gas ($/mcf)								
Excluding hedging	$ 3.18	$ 3.62	$ 3.77	$ 3.72	$ 3.49	$ 3.51	$ 3.81	$ 5.26
Including hedging	$ 3.76	$ 4.16	$ 4.29	$ 4.55	$ 4.81	$ 4.80	$ 5.58	$ 6.87
AECO daily index	$ 3.20	$ 3.66	$ 3.88	$ 3.78	$ 3.63	$ 3.53	$ 3.89	$ 4.95
Crude oil and NGLs ($/bbl)								
Excluding hedging	$ 87.06	$ 76.56	$ 88.27	$ 75.41	$ 69.19	$ 61.84	$ 64.66	$ 67.23
Including hedging	$ 85.88	$ 77.33	$ 86.21	$ 72.82	$ 64.14	$ 59.01	$ 61.80	$ 62.42
WTI ($US/bbl)	$ 94.02	$ 89.81	$ 102.55	$ 94.25	$ 85.18	$ 76.21	$ 77.98	$ 78.79
Total sales including realized hedging	$ 98,858	$ 95,797	$ 99,971	$ 86,488	$ 86,012	$ 83,335	$ 96,377	$ 98,777
Net income (loss)	$ (145,063)	$ (2,997)	$ 997	$ (5,709)	$ (22,889)	$ (659)	$ 31,379	$ 33,089
per share - basic	$ (0.87)	$ (0.02)	$ 0.01	$ (0.03)	$ (0.14)	$ -	$ 0.19	$ 0.20
- diluted	$ (0.87)	$ (0.02)	$ 0.01	$ (0.03)	$ (0.14)	$ -	$ 0.19	$ 0.20
Funds from operations	$ 54,634	$ 50,108	$ 52,041	$ 40,248	$ 40,628	$ 37,698	$ 45,291	$ 49,685

The table above highlights the Corporation’s performance for the fourth quarter of 2011 and also for the preceding seven quarters. Production for the first quarter of 2010 was comparable to the fourth quarter of 2009 but increased dramatically during the second quarter of 2010 as our new gas plant was completed and production from Glacier was increased to between 50 and 55 mmcf/d. We completed two asset dispositions during the end of the second quarter of 2010 representing approximately 1,700 boe/d that resulted in slightly lower production. The full impact of these dispositions resulted in a decrease in production for the third quarter of 2010 with our production remaining relatively consistent through to the first quarter of 2011. Production increased significantly in the second quarter of 2011 as the Phase III expansion at Glacier was completed with production capacity at 100 mmcf/d. Our production has remained comparable for the remainder of 2011 with a modest increase in the fourth quarter from production additions attributed to Longview’s capital expenditure program. Our financial results, particularly sales and funds from operations are significantly impacted by commodity prices. During 2010 and 2011, natural gas prices have remained low which has decreased our corresponding sales and funds from operations, although increasing production and strengthening crude oil and NGLs prices have partially mitigated the impact. Advantage has recognized net losses during 2010 and 2011 primary driven by weak natural gas prices. During these periods we have continued to experience a reduction in costs including royalties, operating expenses, general and administrative expense, and finance expense. We recognized net income in the first and second quarters of 2010 due to higher natural gas prices and a $45.6 million net gain recognized on the disposal of several non-core properties. Our net loss during the fourth quarter of 2011 was considerable as we recognized an impairment loss of $187.7 million related to two CGUs that consist of conventional natural gas focused properties located in Western and Eastern Alberta that had suffered a significant deterioration in value due to the challenging natural gas price environment.

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 crude oil and natural gas prices, operating expense, royalty burden changes, and future development costs. Reserve estimates impact net income and comprehensive income through depreciation and impairment of oil and gas properties. The reserve estimates are also used to assess the borrowing bases 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 bases of the Corporation.

Management’s process of determining the provision for deferred income taxes, the provision for decommissioning liability costs and related accretion expense, the fair values initially assigned to the convertible debentures liability and equity components, and the fair values assigned to any acquired company’s assets and liabilities in a business combination is 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.

International Financial Reporting Standards

Canadian publicly accountable enterprises have implemented International Financial Reporting Standards (“IFRS”) for the fiscal years beginning on or after January 1, 2011. The transition date to IFRS was January 1, 2010 and comparative figures for 2010 and Advantage’s financial position as at January 1, 2010 have been restated to IFRS from the previous Canadian generally accepted accounting principles (“Previous GAAP”). Reconciliations to IFRS from Previous GAAP financial statements including the impact of the transition on the Corporation's reported financial position and financial performance, including the nature and effect of significant changes in accounting policies from those used in the Corporation’s consolidated financial statements for the year ended December 31, 2010, are summarized in note 25 to the unaudited consolidated financial statements. The following discussion explains the significant differences between IFRS and the Previous GAAP followed by the Corporation.

a) Property, plant and equipment

Under Previous GAAP, the Corporation, like many Canadian oil and gas reporting issuers, applied the “full cost” concept in accounting for its oil and gas assets. Under full cost, capital expenditures were maintained in a single cost centre for each country, and the cost centre was subject to a single depletion and depreciation calculation and impairment test. Under IFRS, the Corporation makes a much more detailed assessment of its oil and gas assets that impact depreciation and impairment calculations. Included in this assessment is an ongoing appraisal of exploration and evaluation expenditures (“E&E”). Under Canadian GAAP, it was only necessary to track costs associated with unproved properties that would be excluded from depletion and depreciation calculations. Under IFRS, a company may choose to account for E&E under its previous GAAP and capitalize such costs without recording depreciation expense until the expenditures are determined to represent technically feasible and commercially viable projects at which time the costs are moved to development properties or expensed accordingly. Advantage capitalizes E&E costs except for costs incurred before the acquisition of rights to explore, and to begin depreciating when technically feasible and commercially viable. As at transition on January 1, 2010, $6.9 million was reclassified from property, plant and equipment to exploration and evaluation assets.

As well, under Previous GAAP the Corporation did not recognize gains or losses on the disposal of oil and gas properties unless such dispositions would change the depletion rate by 20% or more while IFRS requires such recognition. This results in an increase to the carrying value and a gain on sale of property, plant and equipment.

b) Depreciation

For Previous GAAP purposes, the full cost method of accounting for oil and gas properties requires a single calculation of depletion and depreciation of the carrying value of PP&E based on proved reserves. However, IFRS requires an allocation of the amount recognized as PP&E to each significant identified component and each component depreciated separately, utilizing an appropriate method of depreciation. This component depreciation of PP&E results in an increased number of calculations of depreciation expense and impacts the amount of depreciation expense recognized. IFRS also permits the option of using either proved or proved and probable reserves in the depreciation calculation. Advantage has utilized proved and probable reserves to calculate depreciation expense as we believe it represents a better approximation of useful life and depletion of reserves.

c) Impairment of Assets

Under Canadian GAAP, impairment calculations are prepared according to a two-step test generally conducted at a country level. Step one involves a comparison of the PP&E carrying value to the undiscounted net cash flows of proved reserves. If a company should fail step one, step two is completed to measure the amount of impairment whereby the PP&E carrying value is compared to a calculated fair value with any excess carrying value above the fair value recognized as an impairment loss. Impairment losses recognized under Canadian GAAP are not subsequently reversed. Under IFRS, impairment testing is completed at an individual asset group or “Cash Generating Unit” level (“CGU”) when indicators suggest there may be impairment. A CGU is defined as the smallest group of assets that produce independent cash flows. Impairment of assets at a CGU level use a one-step approach for testing and measuring asset impairment, with asset carrying values compared to the higher of "Value in Use" and "Fair Value less Costs to Sell". The IFRS methodology may result in the possibility of more frequent impairments in the carrying value of PP&E. However, under IFRS previous impairment losses must be reversed where circumstances change such that the previously recognized impairment has been reduced.

d) Decommissioning Liabilities

Both Canadian GAAP and IFRS require a company to provide for a liability related to decommissioning PP&E. Both methodologies are similar and we have determined there to be no significant difference for Advantage, other than a difference related to discount rates. Canadian GAAP requires that the decommissioning liability be discounted at a credit-adjusted risk-free rate while IFRS requires that the decommissioning liability be discounted at an appropriate rate with either the cash flows or rate adjusted for risks. Advantage has selected to use the risk-free rate for discounting purposes as we believe this accurately represents a market-based rate for such a liability and at transition date the decommission liability was increased $101.1 million and charged to deficit.

e) Convertible debentures liability component

Under Previous GAAP convertible debentures are financial liabilities consisting of a liability with an embedded conversion feature. As such, the debentures were segregated between liabilities and equity and the debenture liabilities are presented at less than their eventual maturity values. The discount of the liability component as compared to maturity value is accreted over the debenture term and expensed accordingly. As debentures are converted to common shares, an appropriate portion of the liability and equity components were transferred to share capital.

Prior to July 9, 2009, Advantage was an Income Trust that operated under the name Advantage Energy Income Fund. As an income trust, convertible debentures were convertible into Trust Units, which contained a redemption feature which effectively made the conversion option a "putable instrument" according to IFRS. As such, convertible debentures were liabilities, with no equity component. Upon conversion to a corporation on July 9, 2009, all convertible debentures became convertible into common shares, and were no longer deemed to contain a "putable instrument". Under IFRS, retrospective restatement of the convertible debentures in existence at July 9, 2009 and still outstanding at transition resulted in the liability component restated to their full maturity values, less any issue costs and no value assigned to the equity component of the conversion features of these same debentures. Accretion expense as recorded under Previous GAAP was reduced, as only debenture issue costs gave rise to accretion expense.

f) Deferred Income Taxes

Deferred income tax calculated according to IFRS is substantially similar to Previous GAAP and arises from differences between the accounting and tax bases of our assets and liabilities. To the extent that assets and liabilities have changed from transition to IFRS, the amount of deferred income tax liability has been impacted. Additionally, under Previous GAAP deferred income tax liabilities were required to be disclosed as either current or long-term. Under IFRS, all deferred income tax liabilities are considered to be non-current liabilities.

g) First Time Adoption of International Financial Reporting Standards

IFRS 1 provides the framework for the first time adoption of IFRS and specifies that an entity shall apply the principles under IFRS retrospectively. IFRS 1 also specifies that the adjustments that arise on retrospective conversion to IFRS from other GAAP should be directly recognized in retained earnings. Certain optional exemptions and mandatory exceptions to retrospective application are provided under IFRS 1. The Corporation has taken the following exemptions:

- Companies using full-cost accounting are allowed to measure their oil and gas assets at the amount determined under the Previous GAAP at the date of transition. This amount is pro-rated to the underlying assets based upon the value of proved and probable reserves at transition date, discounted at 10%.

- Companies using the full cost book value as deemed cost exemption are allowed to measure the liabilities for decommissioning, restoration and similar liabilities at the date of transition and recognize directly in retained earnings any difference between that amount and the carrying amount determined under Previous GAAP.

- IFRS 3 Business Combinations has not been applied to acquisitions of subsidiaries or of interests in associates and joint ventures that occurred before January 1, 2010.

- IFRS 2 Share-based Payment has not been applied to any equity instruments that were granted on or before November 7, 2002, nor has it been applied to equity instruments granted after November 7, 2002 that vested before January 1, 2010.

- IAS 17 Leases has been applied as of transition date rather than at the lease's inception date.

- IAS 32 Financial Instruments Presentation will not be applied for compound financial instruments where the liability component is no longer outstanding.

- IAS 23 Borrowing Costs will not be applied before January 1, 2010.

h) New standards and interpretations not yet adopted

Standards issued but not yet effective up to the date of issuance of the Corporation’s financial statements are listed below. This listing is of standards and interpretations issued which the Corporation reasonably expects to be applicable at a future date. The Corporation intends to adopt those standards when they become effective. The Corporation has yet to assess the full impact of these standards.

Standards issued but not yet effective up to the date of issuance of the Corporation’s financial statements are listed below. This listing is of standards and interpretations issued which the Corporation reasonably expects to be applicable at a future date. The Corporation intends to adopt those standards when they become effective. The Corporation has yet to assess the full impact of these standards.

IFRS 9 Financial Instruments: Classification and Measurement

IFRS 9 is intended to supersede IAS 39, Financial Instruments: Recognition and Measurement and will be published in three phases, of which the first phase has been published. The first phase addresses the accounting for financial assets and financial liabilities. The second phase will address the impairment of financial instruments, and the third phase will address hedge accounting. For financial assets, IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, and replaces the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39. For financial liabilities, although the classification criteria for financial liabilities will not change under IFRS 9, the approach to the fair value option for financial liabilities may require different accounting for changes to the fair value of a financial liability as a result of changes to an entity’s own credit risk. This standard is not applicable until January 1, 2015.

IFRS 10 Consolidated Financial Statements

IFRS 10 is a new standard that will replace SIC 12, “Consolidation – Special Purpose Entities” and IAS 27 “Consolidated and Separate Financial Statements”. The new standard eliminates the current risks and rewards approach and establishes control as the single basis for determining the consolidation of an entity. This standard is not applicable until January 1, 2013.

IFRS 11 Joint Arrangements

IFRS 11 requires a venture to classify its interest in a joint arrangement as a joint venture or joint operation. Joint ventures will be accounted for using the equity method of accounting whereas for a joint operation, the venture will recognize its share of the assets, liabilities, revenue and expenses. Under existing IFRS, entities have the choice to proportionately consolidate or equity account for interests in joint ventures. IFRS 11 supersedes IAS 31, Interests in Joint Ventures and SIC-13, Jointly Controlled Entities, Non-Monetary Contributions by Venturers. This standard is not applicable until January 1, 2013.

IFRS 12 Disclosure of Interests in Other Entities

IFRS 12 provides the required disclosures for interests in subsidiaries and joint arrangements. These disclosures will require information that will assist users of financial statements to evaluate the nature, risks and financial effects associated with an entity’s interests in subsidiaries and joint arrangements. This standard is not applicable until January 1, 2013.

IFRS 13 – Fair Value Measurement

IFRS 13 is a comprehensive standard for fair value measurement and disclosure requirements for use across all IFRS standards. The new standard clarifies that fair value is the price that would be received to sell an asset, or paid to transfer a liability in an orderly transaction between market participants, at the measurement date. It also establishes disclosures about fair value measurement. Under existing IFRS, guidance on measuring and disclosing fair value is dispersed among the specific standards requiring fair value measurement and in many cases does not reflect a clear measurement basis or consistent disclosures. This standard is not applicable until January 1, 2013.

IAS 28 – Investments in Associates and Joint Ventures

IAS 28 has been amended to include joint ventures in its scope and to address the changes in IFRS 10 – 13.

Evaluation of Disclosure Controls and Procedures

Advantage's Chief Executive Officer and Chief Financial Officer have designed disclosure controls and procedures ("DCP"), or caused it to be designed under their supervision, to provide reasonable assurance that all 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 DCP as at December 31, 2011. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that the DCP 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 quarter ended December 31, 2011, 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 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, 2011. 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 affect, the Corporation's internal controls over financial reporting. No material changes in the internal controls were identified during the interim period ended December 31, 2011 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 DCP 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 internal control over financial reporting 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.

Outlook

Advantage's business structure has been established in order to fully capitalize on both natural gas and crude oil exploration and development opportunities. Advantage is focused primarily on developing the significant natural gas resource play at Glacier, Alberta while retaining a significant investment in Longview that is focused on crude oil and natural gas liquids production and development.

Advantage

At Glacier, our continued successful drilling results has increased the quality and magnitude of our Montney natural gas resource which is contained in approximately 300 meters in the Upper, Middle and Lower Montney formations. Our high quality asset at Glacier contains significant scope and scale as validated by Sproule's resource assessment and is underpinned with one of the lowest cost structures in Western Canada which provides Advantage with a significant drilling inventory. Our recent drilling which involved lateral and vertical delineation through the very thick Montney formation across our contiguous land block has added another dimension to Glacier, specifically with the Middle Montney. We estimate that the current drilling inventory at Glacier to be in excess of 900 wells which only includes development of 3 layers in the Montney formation.

Our capital budget for the twelve month period ending June 30, 2012 was set at $216 million of which $200 million is focused on a Phase IV development program at Glacier with two key objectives: i) increase throughput capacity at our Glacier gas plant from 100 mmcf/d to 140 mmcf/d by the second quarter of 2012; and ii) further evaluate the Middle and Lower Montney formations. As a result of the prevailing low natural gas pricing environment, production at Glacier will be maintained between 90 mmcf/d to 100 mmcf/d until we see a sustained increase in natural gas pricing. We will utilize our inventory of 29 gross (28.5 net) Montney wells that have been drilled to maintain targeted production rates at Glacier by producing and/or completing these wells as required. Additionally, we believe that the high industry activity levels that have increased service and supply costs could subside during the latter part of 2012 which would benefit natural gas development economics. We believe that it is prudent to maintain capital spending discipline and financial flexibility in this current natural gas price environment. We also believe that the current price of natural gas is unsustainable for generating sufficient full cycle economic returns in the vast majority of North American natural gas plays and anticipate an improvement in the natural gas price environment. As a result, we are positioning our Glacier gas plant with the capability to ramp up production capacity to 140 mmcf/d by completing modifications as planned in our Phase IV capital program. At this time, we are providing interim guidance for the six months ending June 30, 2012:

Production average	22,800 boe/d to 23,400 boe/d
Royalty rate	8% to 10%
Operating expense	$5.70/boe to $6.00/boe
Capital expenditures	$65 million to $75 million

Additional capital budget and guidance details will be provided pending our evaluation of future delineation plans for our liquids rich Middle Montney formation in order to determine the natural gas and NGL production and reserves potential. This evaluation will include detailed analysis and interpretation of recent geological, engineering and completions data which we obtained from our Middle Montney Phase IV wells. In addition, we have 1 remaining Middle Montney well and 2 Lower Montney wells that are drilled and are awaiting completion which we anticipate undertaking after spring break-up. We expect the results of this information and our evaluation to provide more information in regard to determining a systematic delineation plan for the balance of 2012 and beyond. We will continue with a technically focused and financially disciplined approach to create value from our Glacier property and will revisit our 2012 capital spending plans as required taking into account commodity price and market dynamics.

Longview

With regards to Longview, Advantage has retained a 63% controlling ownership interest with the potential for growth opportunities accompanied by a stable yield. Our investment provides a significant contribution to funds from operations from annual dividends of approximately $17.7 million that will be utilized to partially fund our capital expenditure program. Longview's operations commenced on April 14, 2011 and from April 14 to December 31, 2011, Longview has demonstrated strong financial and operating results with funds from operations supported by high crude oil prices and demonstrated production growth.

Longview's 2011 capital program and routine well maintenance activities were initially delayed due to poor field conditions from severe wet weather during much of the spring and summer. Longview was able to commence their Alberta capital expenditure program in July with the Saskatchewan program beginning in September after delays created by wet weather conditions. Notwithstanding the delays, Longview was able to expedite their efforts and complete their capital expenditure program. Longview deployed two drilling rigs in Alberta and an additional rig targeting the Midale formation in southeast Saskatchewan. As of December 31, 2011, they spent a net $55.0 million and drilled 20.7 net (30 gross) oil wells (100% success rate). This activity significantly increased production whereby Longview daily production averaged 6,823 boe/d for the fourth quarter, an increase of 16% from that realized during their initial quarter ended June 30, 2012.

Longview's 2012 budget is approximately $73 million including the drilling of 25.3 net (34 gross) wells. The following table summarizes operational guidance for Longview for the year ending December 31, 2012:

Production average	6,600 boe/d to 6,800 boe/d
% of oil & liquids	77%
Exit rate	6,800 boe/d to 7,000 boe/d
Production growth %	8%
Royalty rate	18% to 20%
Operating expense	$16.00/boe to $17.00/boe
Capital expenditures	$70 million to $75 million

Longview has contracted three rigs, two of which will target Alberta prospects and the additional rig will target the Midale formation in southeast Saskatchewan. The capital expenditure program also includes analysis of cores that were taken from the Duvernay and Nordegg shale formations on a well that was drilled at Sunset in the fourth quarter of 2011. Detailed core analysis is expected by summer of 2012.

Longview has begun executing their 2012 capital program, focusing on operational and cost efficiencies to increase returns and produce stable cash flows with a conservative financial structure. Longview's business strategy is to provide shareholders with attractive long term returns that combine both growth and yield by exploiting their assets in a financially disciplined manner and by acquiring additional long-life oil and gas assets of a similar nature.

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 annual information circular – proxy statement, 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 23, 2012