Q1

2011 First Quarter Report

Financial and Operating Highlights

	Three months ended March 31, 2011		Three months ended March 31, 2010	
Financial ($000, except as otherwise indicated)				
Sales including realized hedging	$	86,488	$	98,777
per share (1)	$	0.53	$	0.61
per boe	$	38.78	$	48.71
Funds from operations	$	40,248	$	49,685
per share (1)	$	0.24	$	0.30
per boe	$	18.05	$	24.50
Net income (loss)	$	(5,709)	$	33,089
per share (1)	$	(0.03)	$	0.20
Expenditures on property, plant and equipment	$	76,995	$	68,330
Working capital deficit (2)	$	44,582	$	58,862
Bank indebtedness	$	347,353	$	257,259
Convertible debentures (face value)	$	148,544	$	218,471
Shares outstanding at end of period (000)		164,556		163,066
Basic weighted average shares (000)		164,489		163,021
Operating				
Daily Production				
Natural gas (mcf/d)		111,145		87,346
Crude oil and NGLs (bbls/d)		6,251		7,975
Total boe/d @ 6:1		24,775		22,533
Average prices (including hedging)				
Natural gas ($/mcf)	$	4.55	$	6.87
Crude oil and NGLs ($/bbl)	$	72.82	$	62.42

(1) based on basic weighted average shares outstanding

(2) working capital deficit includes trade and other receivables, prepaid expenses and deposits, trade and other accrued liabilities, and the current portion of capital lease obligations

MESSAGE TO SHAREHOLDERS

Production Growth Continues with Reduced Costs and Hedging Gains

- Production for the first quarter of 2011 averaged 24,775 boe/d, an increase of 19% as compared to the first quarter of 2010, after adjusting for non-core asset dispositions. Advantage's daily production for March 2011 exited at approximately 30,000 boe/d, due to stronger than expected well performance at Glacier and earlier commissioning of the Glacier gas plant expansion to a production capacity of 100 mmcf/d.
- Funds from operations for the first quarter of 2011 was $40.2 million or $0.24 per share, lower as compared to the $49.7 million or $0.30 per share for the first quarter of 2010. Funds from operations during the first quarter of 2011 was supported by increased production, reduced costs and hedging gains of $6.9 million which partially offset a 29% decrease in realized natural gas pricing.
- Operating expense for the first quarter of 2011 decreased 13% to $10.08/boe as compared to $11.64/boe during the first quarter of 2010 and a decrease of 5% as compared to $10.56/boe for the fourth quarter of 2010. Operating expense per boe has decreased considerably over the last several years as a result of the increasing contribution of low cost production from Glacier, the continued optimization of our other properties, and the disposition of higher cost non-core assets. We anticipate corporate operating expense will decline further in 2011 as a result of increased production at Glacier.
- The royalty rate for the first quarter of 2011 as a percentage of sales was 14.3% as compared to 14.7% during the first quarter of 2010. We anticipate that our corporate royalty rate will decline further due to increasing production from Glacier where the effective royalty rate for a new Glacier Montney well is estimated to be approximately 5% over the life of the well.
- As at March 31, 2011, Advantage's bank debt was $347.4 million on a credit facility of $525 million resulting in an unutilized capacity of approximately $173.9 million. Our bank indebtedness increased during the first quarter due to ongoing capital activity at Glacier, Alberta that culminated in the completion of our Phase III Montney development program at the end of March.
- A total of $148.5 million of convertible debentures remain outstanding of which $62.3 million will mature in December 2011 and the balance of $86.2 million will mature in January 2015.
- Capital expenditures during the first quarter of 2011 amounted to $77.0 million. Approximately 83% of our 2011 capital spending has been invested at Glacier where we completed Phase III of our development program in the first quarter of 2011 ahead of time and on-budget. The Phase III development program at Glacier consisted of drilling 28 net (28 gross) horizontal wells and expanding our Glacier gas plant and gathering system capacity to 100 mmcf/d.

Successful Phase III Development Program at Glacier Positions Advantage with a Multi-Decade Montney Drill Inventory

- Our Phase III capital development program at Glacier was completed ahead of schedule and on-budget during the first quarter of 2011 which resulted in a March 2011 exit rate of 100 mmcf/d.
- Production performance at Glacier has been higher than anticipated with average daily natural gas production in excess of 60 mmcf/d during the first quarter of 2011 and exiting March 2011 at 100 mmcf/d (16,600 boe/d).
- Operating costs at Glacier are forecast to decrease to approximately $1.80/boe ($0.30/mcf) due to efficiencies created by increased production through Advantage's 100% owned Glacier gas plant and the utilization of multi-well production well pads on our land block which simplifies field operations.
- All Montney horizontal wells drilled at Glacier after May 1, 2010 qualify for a royalty incentive of $2.7 to $3.4 million based on a typical Glacier Montney horizontal well (total length of 4,200 to 4,500 metres). As a result, the effective royalty rate for a new Glacier Montney well is anticipated to be approximately 5% over the life of the well.

Phase III Montney Drilling Results

- In the Upper Montney, drilling results in the extreme northeast and southeast areas of our land block exceeded our expectations and has confirmed the continuation of high quality Upper Montney reservoir characteristics which further proved up significant undrilled acreage. As an example, a four well pad located in the northeast area of our land block tested at an average combined rate of 36 mmcf/d. These results are better than expected and our technical team is currently integrating this into our Montney database that will provide additional information to re-calibrate the future growth potential of our land block. Overall, a total of 24 gross (24 net) Upper Montney wells were drilled as part of our Phase III program which resulted in an average per well test rate of 8.2 mmcf/d which exceeded expectations.
- In the Lower Montney, Advantage has drilled a total of 12 gross (8.7 net) horizontal wells since 2008 including 4 gross (4 net) wells as part of our Phase III program. The Lower Montney wells to date demonstrate a lower average 30 day initial production rate but exhibit shallower declines which indicates significant reserve potential. We believe that opportunities exist

to increase the initial well productivity through improved frac design technology. The Lower Montney is present over the entire Glacier land block and provides a significant opportunity for future reserves growth.

- As part of the Phase III program, two of the Upper Montney wells were partially drilled into the Middle Montney formation. Advantage is encouraged by the resource potential in this horizon. Further evaluation and delineation of this formation is required to prove up reserves in this zone as no reserves were assigned in our 2010 year-end Sproule Reserve Report.
- Since 2008, a total of 60.0 net Montney horizontal wells (51.3 net Upper Montney and 8.7 net Lower Montney) have been drilled on our 80 net section land block. This results in a drilling density of less than 1 well per section and with a total Montney formation pay thickness of approximately 290 meters, Advantage believes our Montney well inventory could be in excess of 800 wells.
- Glacier is a unique asset which provides the opportunity for Advantage to develop a large, scaleable natural gas resource play which contains decades of drilling inventory and with one of the lowest cost structures in the Western Canadian Sedimentary Basin.

Commodity Hedging Program

- Advantage's hedging program includes 28.4 mmcf/d of natural gas for 2011 hedged at an average price of Cdn$6.25 AECO per mcf and 1,500 bbls/d of crude oil for 2011 hedged at an average price of Cdn$91.05 per bbl.
- Additional details on our hedging program are available at our website at www.advantageog.com.

Creation of Longview Oil Corp.

- On March 7, 2011 Advantage announced that Longview Oil Corp. ("Longview"), a wholly-owned subsidiary of the Corporation, filed a preliminary prospectus on March 4, 2011 for an initial public offering (the "Offering"), to raise gross proceeds of $172.5 million including an over-allotment option of up to 15% of the base offering size, exercisable 30 days following the closing of the Offering. The final prospectus was filed on April 6, 2011, the Offering closed on April 14, 2011 and the over-allotment option was exercised in full on April 28, 2011.
- Concurrent with closing of the Offering, Longview purchased certain oil-weighted assets from Advantage with consideration comprised of $245.5 million and 29,450,000 common shares of Longview representing a 63% equity ownership. The assets had first quarter 2011 average production of 6,070 boe/d, and December 31, 2010 proved reserves of 20.1 mmboe and proved plus probable reserves of 36.9 mmboe. Advantage used the cash proceeds to reduce outstanding bank indebtedness.
- As the disposition of the assets to Longview occurred after March 31, 2011 and is not reflected within Advantage's financial and operating results for the current quarter, we have provided the following supplemental information summarizing production, operating income and expenditures on property, plant and equipment for the three months ended March 31, 2011 relating to the specific assets subsequently owned by each of Advantage and Longview.

	ADVANTAGE Three months ended March 31, 2011	LONGVIEW Three months ended March 31, 2011
Daily production		
Natural gas (mcf/d)	102,322	8,823
Crude oil (bbls/d)	526	4,011
NGLs (bbls/d)	1,126	588
Total (boe/d)	**18,705**	**6,070**
Natural gas (%)	91%	24%
Crude oil (%)	3%	66%
NGLs (%)	6%	10%

	ADVANTAGE Three months ended March 31, 2011 $000	 per boe	LONGVIEW Three months ended March 31, 2011 $000	 per boe
Sales				
Crude oil and NGLs	$ 10,805		$ 31,621	
Natural gas	34,011		3,195	
Total sales	44,816	$ 26.62	34,816	$ 63.73
Royalties	(4,564)	(2.71)	(6,862)	(12.56)
Royalty %	*10.2%*		*19.7%*	
Operating expense	(13,708)	(8.14)	(8,779)	(16.07)
Operating income	**$ 26,544**	**$ 15.77**	**$ 19,175**	**$ 35.10**
Realized gain (loss) on derivatives	7,104	4.22	(248)	(0.45)
Cash netback	**$ 33,648**	**$ 19.99**	**$ 18,927**	**$ 34.65**
Expenditures on property, plant and equipment	$ 66,603		$ 10,392	

- For the three months ended March 31, 2011, production from the assets disposed to Longview was 6,070 boe/d, reflective of industry declines since the fourth quarter of 2010. During the first quarter of 2011, Advantage incurred production optimization expenditures including workovers that increased operating costs.
- Advantage spent $10.4 million in the first quarter of 2011 related to the Longview assets, including the drilling of 6.8 net wells at a 100% success rate. Drilling activity included 3 net wells at Eyehill, 2 net wells at Nevis, 0.6 net wells at Alameda, and Cardium drilling activity at Brazeau/Ferrier. All of these wells have been cased and will be brought on production in the second quarter of 2011. With the creation of Longview, the capital expenditure program on these assets will accelerate along with other operating activities. We have contracted three rigs which will begin drilling subsequent to spring breakup. Two of the rigs will target Alberta prospects and the additional rig will target the Midale formation in southeast Saskatchewan.
- **As a result of the successful completion of the transaction, historical financial and operating performance as well as forward-looking information may not be indicative of actual future performance.**
- For further details, please refer to the press release issued by Advantage on March 7, 2011 and the final prospectus filed by Longview on April 6, 2011, which are available at www.sedar.com and Longview's website at www.longviewoil.com.

Looking Forward

- Drilling results at our cornerstone Glacier property have demonstrated that our Montney development is among the top tier natural gas resource developments in North America. The attractive cost structure at Glacier which includes low operating costs and low royalty rates combined with a multi-decade drilling inventory provides a strong foundation to drive future development beyond 100 mmcf/d of production.
- For the second quarter of 2011, we anticipate production at Glacier will average approximately 90 to 95 mmcf/d due to compressor maintenance on the TransCanada pipeline system which will result in pressure restrictions and temporary outages. Advantage's production (net of Longview) is expected to be approximately 23,500 boe/d for the second quarter of 2011.
- With the Phase III development program completed at Glacier, a review of well performance, updated geological and reservoir data, facility capacity and actual costs will be undertaken by Advantage to assess the timing and capital requirements for the next phase of growth at Glacier.
- Advantage will provide additional corporate guidance and communicate future development plans on or about mid-year 2011.

Interim Consolidated Financial Statements and MD&A

- Advantage's unaudited interim consolidated financial statements for the three months ended March 31, 2011 together with the notes thereto, and Management's Discussion and Analysis for the three months ended March 31, 2011 have been prepared in accordance with International Financial Reporting Standards ("IFRS") and posted on our website at www.advantageog.com and filed under our profile on SEDAR at www.sedar.com.

Management's Discussion & Analysis

The following Management's Discussion and Analysis ("MD&A"), dated as of May 12, 2011, provides a detailed explanation of the financial and operating results of Advantage Oil & Gas Ltd. ("Advantage", the "Corporation", "us", "we" or "our") for the three months ended March 31, 2011 and should be read in conjunction with the unaudited consolidated financial statements for the three months ended March 31, 2011 and the audited consolidated financial statements and MD&A for the year ended December 31, 2010. All per barrel of oil equivalent ("boe") amounts are stated at a conversion rate of six thousand cubic feet of natural gas being equal to one barrel of oil or liquids, based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Boes may be misleading, particularly if used in isolation.

Transition to International Financial Reporting Standards

The consolidated financial statements, MD&A and comparative information have been prepared in Canadian dollars unless otherwise indicated and in accordance with International Financial Reporting Standards ("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, 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 22 to the unaudited 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 spending and capital budgets; capital expenditure programs; the focus of capital expenditures; availability of funds for our capital program; effect on production due to completion of facilities and infrastructure expansion work in Glacier, Alberta; expected production from the Glacier development project; our future operating and financial results; supply and demand for oil and natural gas; effect of natural gas prices on drilling activity and supply levels; projections of market prices and costs; effect of natural gas and oil prices on the Corporation's financial performance; the size of, and future net revenues from, reserves; the performance characteristics of our properties; effect on income of the Corporation's derivative and hedging activities; the Corporation's hedging strategy; effect of the Corporation's risk management activities; projected royalty rates; average royalty rates; plans to improve operating cost structure and effect on corporate operating costs; the amount of general and administrative expenses; terms of the Corporation's credit facility; and terms of the transaction with Longview Oil Corp. 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 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. Many of these 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: 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; and the impact of increasing competition.

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.

This MD&A discusses historical financial and operating performance as well as forward-looking information for the Corporation excluding any potential impacts that may occur due to completion of the transaction with Longview Oil Corp. on April 14, 2011 (see section “Creation of Longview Oil Corp.”). As a result, historical financial and operating performance as well as forward-looking information may not be indicative of actual future performance.

Non-GAAP Measures

The Corporation discloses several financial measures in the MD&A that do not have any standardized meaning prescribed under GAAP. These financial measures include funds from operations and cash netbacks. Management believes that these financial measures are useful supplemental information to analyze operating performance and provide an indication of the results generated by the Corporation’s principal business activities. Investors should be cautioned that these measures should not be construed as an alternative to net income, 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 financing expense. Cash netbacks are dependent on the determination of funds from operations and include the primary cash revenues and expenses on a per boe basis that comprise funds from operations. Funds from operations reconciled to cash provided by operating activities is as follows:

	Three months ended March 31		
($000)	**2011**	**2010**	**% change**
Cash provided by operating activities	$ 24,581	$ 52,298	(53) %
Expenditures on decommissioning liability	1,038	1,392	(25) %
Changes in non-cash working capital	20,800	3,083	575 %
Financing expense (1)	(6,171)	(7,088)	(13) %
Funds from operations	**$ 40,248**	**$ 49,685**	**(19) %**

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

Overview

	Three months ended March 31 2011	2010	% change
Cash provided by operating activities ($000)	$ 24,581	$ 52,298	(53) %
Funds from operations ($000)	$ 40,248	$ 49,685	(19) %
per share [1]	$ 0.24	$ 0.30	(20) %
per boe	$ 18.05	$ 24.50	(26) %

(1) Based on basic weighted average shares outstanding.

For the three months ended March 31, 2011 we continued to realize significant gains on derivatives which amounted to $6.9 million that has helped to offset the continued weak natural gas prices and positively impact funds from operations. However, hedging gains for 2011 has been lower than 2010 as we had a lower percentage of natural gas production hedged at lower average prices. Funds from operations has also benefited during this quarter from higher crude oil prices and continued cost reductions, such as operating costs and finance expense. Unfortunately, natural gas prices still remain weak and pose a continuing challenge to the entire natural gas industry. 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 the three months ended March 31, 2011 compared to the same period of 2010 with all revenues and expenses generally impacted. When comparing the current quarter to the fourth quarter of 2010, our funds from operations per boe of $18.05 was marginally higher than the $17.97 from the prior quarter. Cash provided by operating activities has decreased more during 2011 as compared to the same period of the prior year due to the increase in working capital from the payment of trade payables and other liabilities during the quarter due to an active winter development program.

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, and net 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 and Natural Gas Sales and Hedging

($000)	Three months ended March 31 2011	2010	% change
Natural gas sales	$ 37,206	$ 41,310	(10) %
Realized hedging gains	8,317	12,666	(34) %
Natural gas sales including hedging	$ 45,523	$ 53,976	(16) %
Crude oil and NGLs sales	$ 42,426	$ 48,250	(12) %
Realized hedging losses	(1,461)	(3,449)	(58) %
Crude oil and NGLs sales including hedging	$ 40,965	$ 44,801	(9) %
Total [1]	**$ 86,488**	**$ 98,777**	**(12) %**

(1) Total excludes unrealized derivative gains and losses.

Total sales, excluding hedging, was adversely impacted for the three months ended March 31, 2011, as compared to 2010, primarily due to lower natural gas prices and production attributable to asset dispositions that closed in the second quarter of 2010. However, excluding the asset dispositions, production increased 19% for the three months ended March 31, 2011 as compared to 2010 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 facilities and infrastructure expansion work that was completed in the first quarter of 2011. Total sales were also positively impacted for the first quarter of 2011 by higher crude oil and NGLs prices, excluding hedging. However, overall total sales have decreased primarily due to natural gas prices that have been weak during the last several years attributable to many factors, including the recession in the North American economy that has generally reduced energy demand and higher North American natural gas production, both of which have maintained relatively high natural gas inventory levels.

Given the low natural gas price environment, our commodity price risk management program has delivered realized natural gas hedging gains of $8.3 million for the three months ended March 31, 2011. As crude oil prices have continued to strengthen, we realized crude oil hedging losses of $1.5 million for the three months ended March 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.

Production

	Three months ended March 31		
	2011	**2010**	**% change**
Natural gas (mcf/d)	111,145	87,346	27 %
Crude oil (bbls/d)	4,537	5,511	(18) %
NGLs (bbls/d)	1,714	2,464	(30) %
Total (boe/d)	**24,775**	**22,533**	**10 %**
Natural gas (%)	75%	65%	
Crude oil (%)	18%	24%	
NGLs (%)	7%	11%	

Average daily production during the first quarter of 2011 increased 10% above the same period of 2010, with the 27% increase in natural gas production partially offset by decreases in both crude oil and NGLs production. Production from the first quarter of 2010 includes approximately 1,745 boe/d related to assets disposed during 2010. After excluding production from these asset dispositions, Advantage's average daily production for the first quarter of 2011 increased approximately 19%, as compared to the same period of 2010. Average daily production for the first quarter of 2011 was 2% higher as compared to the 24,308 boe/d reported in the fourth quarter of 2010. Production for 2010 and 2011 has continued to be positively impacted by the significant production growth at Glacier, Alberta. During the second quarter of 2010 our new 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 substantially 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 corporate March exit daily production rate of approximately 30,000 boe/d. Well productivity from the Phase III development program resulted in significant production capability exceeding the Glacier gas plant capacity with additional wells that will be brought on-stream as required to offset declines and maintain production levels.

Commodity Prices and Marketing

Natural Gas

($/mcf)	Three months ended March 31 2011	Three months ended March 31 2010	% change
Realized natural gas prices			
Excluding hedging	$ 3.72	$ 5.26	(29) %
Including hedging	$ 4.55	$ 6.87	(34) %
AECO monthly index	$ 3.77	$ 5.35	(30) %

Realized natural gas prices, excluding hedging, were 29% lower for the three months ended March 31, 2011 as compared to the same period of 2010. Our realized natural gas prices, excluding hedging, for this quarter increased 7% from the $3.49/mcf realized during the fourth quarter of 2010. Although natural gas prices have continued to remain weak, our commodity hedging strategy has resulted in realized natural gas prices, including hedging, that exceeds current market prices and has reduced the volatility of our cash flows.

During 2010 and 2011, natural gas prices have remained low 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 have resulted in generally higher inventory and have placed considerable downward pressure on natural gas prices. The 2009/2010 winter season experienced stronger inventory withdraws which helped to modestly strengthen prices in early 2010. However, as we exited the winter, natural gas prices significantly decreased and remained weak throughout 2010. During the 2010/2011 winter we have seen reasonable storage withdraws that has helped to reduce natural gas inventory to approximately the five-year average. Nevertheless, natural gas prices continue to remain weak as we exited the winter. We continue to believe in the longer-term price support for natural gas due to increased drilling for new 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 continue to 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 March 31 2011	Three months ended March 31 2010	% change
Realized crude oil prices			
Excluding hedging	$ 81.34	$ 74.97	8 %
Including hedging	$ 77.77	$ 68.01	14 %
Realized NGLs prices			
Excluding hedging	$ 59.71	$ 49.91	20 %
Realized crude oil and NGLs prices			
Excluding hedging	$ 75.41	$ 67.23	12 %
Including hedging	$ 72.82	$ 62.42	17 %
WTI ($US/bbl)	$ 94.25	$ 78.79	20 %
$US/$Canadian exchange rate	$ 1.01	$ 0.96	5 %

Realized crude oil and NGLs prices, excluding hedging, increased 12% for the three months ended March 31, 2011, as compared to the same period of 2010. As compared to the fourth quarter of 2010, realized crude oil and NGLs prices, excluding hedging, have increased 9% for the first quarter of 2011. Advantage's realized crude oil price may not change to the same extent as West Texas Intermediate ("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. There has been significant price volatility experienced over the last several years with WTI increasing throughout 2009 and remaining relatively strong during 2010. Near the end of 2010, WTI began to increase and significantly escalated during early 2011, primarily influenced by middle-east civil unrest and associated supply concerns, with WTI currently trading at approximately US$100/bbl. However, we have also seen a constant strengthening of the $US/$Canadian exchange rate during these periods such that our increase in realized price has been less than the improvement in WTI. We continue to 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 many 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 could 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 that are members of our credit facility syndicate 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.

We have historically been active in entering financial contracts to protect future cash flows and currently the Corporation has the following derivatives in place:

Description of Derivative	Term	Volume	Average Price
Natural gas - AECO			
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
		28,434 mcf/d	Cdn$6.25/mcf
Crude oil – WTI			
Fixed price (1)	January 2011 to December 2011	1,500 bbls/d	Cdn$91.05/bbl

(1) This financial contract was assumed by Longview Oil Corp. on April 14, 2011 (see section "Creation of Longview Oil Corp.").

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

	Three months ended March 31		
($000)	**2011**	**2010**	**% change**
Realized hedging			
Natural gas	$ 8,317	$ 12,666	(34) %
Crude oil	(1,461)	(3,449)	(58) %
Total realized hedging gains	$ 6,856	$ 9,217	(26) %
Unrealized hedging			
Natural gas	$ (7,062)	$ 22,438	(131) %
Crude oil	(3,069)	3,673	(184) %
Total unrealized hedging gains (losses)	$ (10,131)	$ 26,111	(139) %
Total gains (losses) on derivatives	**$ (3,275)**	**$ 35,328**	**(109) %**

For the three months ended March 31, 2011, we recognized a net realized derivative gain of $6.9 million (March 31, 2010 - $9.2 million net realized derivative gain) on settled derivative contracts as a result of lower average natural gas prices compared to our established average hedge prices. Our net realized derivative gain has decreased during 2011 as compared to 2010 as we have less natural gas production hedged for this year at lower average prices and we realized losses on our crude oil hedges as WTI prices increased. However, our successful commodity price risk management program continued to realize significant gains on derivatives for the three months ended March 31, 2011 that has helped to offset the continued weak natural gas prices and positively impact funds from operations. As at March 31, 2011, the fair value of the derivative contracts outstanding and to be settled was a net asset of approximately $12.5 million, a decrease of $10.1 million from the $22.6 million net asset recognized as at December 31, 2010. For the three months ended March 31, 2011, this $10.1 million decrease was recognized in income as an unrealized derivative loss (March 31, 2010 – $26.1 million unrealized derivative gain). The valuation of the derivatives is the estimated fair value to settle the contracts as at March 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 (loss) 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 2011 corresponding to when the Corporation will recognize sales from production.

Royalties

	Three months ended March 31		
	2011	2010	% change
Royalties ($000)	$ 11,426	$ 13,189	(13) %
per boe	$ 5.12	$ 6.50	(21) %
As a percentage of petroleum and natural gas sales	14.3%	14.7%	(0.4) %

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. Royalty expense includes 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 and royalties as a percentage of petroleum and natural gas sales decreased for the three months ended March 31, 2011 compared to the same period of 2010 due to lower natural gas prices and lower average royalties attributed to production from our significant development at Glacier, Alberta offset partially by higher crude oil royalty rates.

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 implemented a number of drilling incentive programs with reduced royalty rates over a period of time for qualifying wells. The majority of our wells brought on production since April 1, 2009 qualify and benefit from a 5% royalty rate on the first 500 mmcf produced or one-year, whichever occurs first, and a drilling credit of $200 per metre drilled that reduces capital spending. The reduced 5% royalty rate program is a permanent incentive while the drilling credit incentives are effective for qualifying wells drilled and brought on production from April 1, 2009 to March 31, 2011. The Alberta Provincial Government also made changes in the Natural Gas Deep Drilling Program ("NGDDP") which reduces the vertical depth requirement to 2,000 metres (from 2,500 metres). As a result, all of our Montney horizontal wells at Glacier drilled after May 1, 2010 qualify for the NGDDP which is estimated to provide an additional 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% to 7% 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, Alberta royalty rates will continue to fluctuate based on commodity prices, individual well productivity, and our ongoing capital development plans.

Operating Expense

	Three months ended March 31		
	2011	2010	% change
Operating expense ($000)	$ 22,487	$ 23,606	(5) %
per boe	$ 10.08	$ 11.64	(13) %

Total operating expense decreased 5% for the three months ended March 31, 2011 as compared to the same period of 2010. The reduction in total operating expense has been primarily due to increased production from Glacier, benefits of our ongoing optimization program and the sale of higher cost assets. Operating expense per boe decreased 13% and we anticipate corporate operating expense will decline further in 2011 as a result of increasing production at Glacier. We estimate that operating expense at Glacier will reduce to a target of approximately $1.80/boe ($0.30/mcf) at 100 mmcf/d due to the efficiencies created by increasing the production rate through our 100% owned Glacier gas plant.

General and Administrative Expense

	Three months ended March 31		
	2011	2010	% change
General and administrative expense			
Cash expense ($000)	$ 6,181	$ 5,715	8 %
per boe	$ 2.77	$ 2.82	(2) %
Non-cash expense ($000)	$ 2,175	$ 3,751	(42) %
per boe	$ 0.98	$ 1.85	(47) %
Total general and administrative expense ($000)	$ 8,356	$ 9,466	(12) %
per boe	$ 3.75	$ 4.67	(20) %
Employees at March 31	126	131	(4) %

Cash general and administrative ("G&A") expense for the three months ended March 31, 2011 has increased modestly as compared to the same period of 2010 due to incremental costs incurred in 2011 associated with the creation of Longview Oil Corp.

Non-cash G&A expense for the three months ended March 31, 2011 decreased 42% as compared to the same period of 2010. Non-cash G&A expense is primarily comprised of Advantage's Restricted Share Performance Incentive Plan ("RSPIP" or the "Plan") as approved by the shareholders 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 return. The Plan authorizes the Board of Directors to grant restricted shares to service providers of the Corporation, including directors, officers, employees and consultants. 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. 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. Compensation cost related to the Plan is recognized as share-based compensation expense within G&A expense over the service period and incorporates the share grant price, the estimated number of restricted shares to vest, and certain management estimates. For the three months ended March 31, 2011, we granted 67,343 restricted shares at an average grant price of $6.95 per restricted share and recognized $2.2 million of share-based compensation expense as non-cash G&A expense related to restricted shares granted to service providers. During the three months ended March 31, 2011 we issued 463,576 shares to service providers in accordance with the vesting provisions of the Plan. As at March 31, 2011, 2,508,200 restricted shares remain unvested and will vest to service providers over the next two years with a total of $5.8 million in compensation cost to be recognized over the future service periods.

Depreciation Expense

	Three months ended March 31		
	2011	2010	% change
Depreciation expense ($000)	$ 32,406	$ 28,229	15 %
per boe	$ 14.53	$ 13.92	4 %

Depreciation of oil and gas properties is provided on the "unit-of–production" method based on total proved and probable reserves on a component basis. The depreciation expense has increased for the three months ended March 31, 2011 as compared to 2010 due to the 10% increase in production and a slightly higher average rate of depreciation per boe due to our active and ongoing capital development program, primarily focused at Glacier, Alberta.

Exploration and Evaluation Expense

	Three months ended March 31		
	2011	2010	% change
Exploration and evaluation expense ($000)	$ 205	$ -	100 %
per boe	$ 0.09	$ -	100 %

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 three months ended March 31, 2011, we expensed exploration and evaluation costs of $0.2 million related to previously acquired undeveloped land that expired during the quarter.

Other Income

	Three months ended March 31		
($000)	2011	2010	% change
Gain on sale of property, plant and equipment	$ 76	$ 4,037	(98) %
Miscellaneous income	25	506	(95) %
	$ 101	$ 4,543	(98) %

Other income primarily consists of gains related to the disposition of property, plant and equipment. During the first quarter of 2010, Advantage disposed of a non-core property and recognized a $4.0 million gain. For the first quarter of 2011, there were minor adjustments related to previously recognized gains and losses from asset dispositions.

Interest on Bank Indebtedness

	Three months ended March 31 2011	2010	% change
Interest on bank indebtedness ($000)	$ 3,908	$ 3,704	6 %
per boe	$ 1.75	$ 1.83	(4) %
Average effective interest rate	5.5%	5.3%	0.2 %
Bank indebtedness at March 31 ($000)	$ 347,353	$ 257,259	35 %

Total interest on bank indebtedness modestly increased 6% for the three months ended March 31, 2011 as compared to 2010 primarily due to the higher average debt balance during the period attributable to our active capital development program. Bank indebtedness outstanding at the end of March 31, 2011 increased as compared to the prior period due to the capital development program and the 6.50% convertible debentures that matured and were settled with $69.9 million in cash on June 30, 2010. As a result of the disposition of oil-weighted assets to Longview Oil Corp. that closed on April 14, 2011, the Advantage credit facility was reduced to $275 million (see section "Creation of Longview Oil Corp.") and net cash proceeds received of $245.5 million was used to reduced bank indebtedness. 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. Our current credit facilities have been a favorable financing alternative with an effective interest rate of 5.5% for the three months ended March 31, 2011.

Interest and Accretion on Convertible Debentures

	Three months ended March 31 2011	2010	% change
Interest on convertible debentures ($000)	$ 2,263	$ 3,384	(33) %
per boe	$ 1.01	$ 1.67	(40) %
Accretion on convertible debentures ($000)	$ 837	$ 804	4 %
per boe	$ 0.38	$ 0.40	(5) %
Convertible debentures maturity value at March 31 ($000)	$ 148,544	$ 218,471	(32) %

Interest on convertible debentures for the three months ended March 31, 2011 has decreased compared to 2010 due to the maturity of the 6.50% debentures on June 30, 2010. Accretion on convertible debentures has remained comparable for the three months ended March 31, 2011.

Accretion on Decommissioning Liability

	Three months ended March 31 2011	2010	% change
Accretion on decommissioning liability ($000)	$ 1,607	$ 1,701	(6) %
per boe	$ 0.72	$ 0.84	(14) %

Accretion on the 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 3.72% of the liability. Accretion expense has decreased slightly due to a decrease in our decommissioning liability associated with property dispositions during 2010.

Taxes

Deferred income taxes arise from differences between the accounting and tax bases of our assets and liabilities. For the three months ended March 31, 2011, the Corporation recognized a deferred income tax recovery of $1.4 million compared to a deferred income tax expense of $12.2 million for the same period of 2010. The deferred income tax recovery was recognized in 2011 due to the $7.1 million realized loss before taxes as compared to the $45.3 million income before taxes for 2010. As at March 31, 2011, the Corporation had a total deferred income tax liability balance of $38.9 million, compared to $40.2 million at December 31, 2010.

Net Income (Loss) and Comprehensive Income (Loss)

	Three months ended March 31		
	2011	2010	% change
Net income (loss) and comprehensive income (loss) ($000)	$ (5,709)	$ 33,089	(117) %
per share - basic	$ (0.03)	$ 0.20	(115) %
- diluted	$ (0.03)	$ 0.20	(115) %

Net loss and net loss per share was realized for the three months ended March 31, 2011 as compared to the net income and net income per share for the same quarter of 2010, primarily due to the gains on derivatives for 2010 that have not been recognized in 2011. A significant portion of the derivatives gains recognized in 2010 were unrealized and represented the fair value of the derivative contracts outstanding and to be settled. 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 (loss) as a derivative gain or loss with a corresponding derivative asset and liability recorded on the statement of financial position. Our realized derivative gains have also decreased during 2011 as compared to 2010 as we have less natural gas production hedged for this year at lower average prices and we realized losses on our crude oil hedges as WTI prices increased. Revenue for 2011 has been positively impacted by a 10% increase in production as compared to the same period of 2010, but was more than offset by a 29% decrease in realized natural gas prices, excluding hedging. Our major challenge continues to be the natural gas price environment that has remained weak and adversely impacts revenue. The higher production for 2011 has contributed to a 15% increase in depreciation expense that negatively impacted income. Operating costs have continued to improve through increased production volumes at Glacier, divestment of higher cost non-core assets and an aggressive optimization program that continues to demonstrate positive benefits. We anticipate that corporate operating costs will further improve as a result of increasing lower cost production from our Glacier property.

Cash Netbacks

	Three months ended March 31			
	2011		2010	
	$000	per boe	$000	per boe
Petroleum and natural gas sales	$ 79,632	$ 35.71	$ 89,560	$ 44.16
Royalties	(11,426)	(5.12)	(13,189)	(6.50)
Realized gain on derivatives	6,856	3.07	9,217	4.55
Operating expense	(22,487)	(10.08)	(23,606)	(11.64)
Operating	**$ 52,575**	**$ 23.58**	**$ 61,982**	**$ 30.57**
General and administrative (1)	(6,181)	(2.77)	(5,715)	(2.82)
Financing expense (2)	(6,171)	(2.77)	(7,088)	(3.50)
Miscellaneous income	$ 25	$ 0.01	506	$ 0.25
Funds from operations and cash netbacks	**$ 40,248**	**$ 18.05**	**$ 49,685**	**$ 24.50**

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

Funds from operations decreased in total for the three months ended March 31, 2011 as compared to the same period of 2010 partially due to asset dispositions completed in the second quarter of 2010 that generally impacted all revenues and expenses. However, funds from operations have been positively impacted during 2011 as compared to the 2010 period due to completion of the Glacier gas plant in the second quarter of 2010 to a production capacity exceeding 50 mmcf/d (8,300 boe/d). Due to stronger than expected well performance, we were able to exit 2010 with Glacier production exceeding 60 mmcf/d (10,000 boe/d) and the

Phase III expansion to a production capacity of 100 mmcf/d (16,667 boe/d) was substantially completed near the end of the current quarter. Funds from operations were adversely impacted during the quarter due to lower realized derivative gains as we have less natural gas production hedged for 2011 at lower average prices. However, our successful commodity price risk management program has still enabled us to realize significant gains on derivatives of $6.9 million for the three months ended March 31, 2011 that has helped to offset the continued weak natural gas prices and positively impact funds from operations. Funds from operations has also benefited during this quarter from higher crude oil prices and continued cost reductions. Unfortunately, natural gas prices still remain weak and pose a continuing challenge to the entire natural gas industry. Operating costs per boe 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. Finance expense has also continued to decrease as we utilized proceeds from the asset dispositions to repay bank indebtedness and maturing convertible debentures. The current quarter funds from operations per boe was modestly higher than the $17.97 for the fourth quarter of 2010.

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**	**2011**	**2012**	**2013**	**2014**	**2015**
Building leases	$ 10.0	$ 2.6	$ 3.4	$ 2.5	$ 1.5	$ -
Pipeline/transportation	34.0	6.9	9.1	8.6	7.4	2.0
Bank indebtedness (1)	347.4	-	347.4	-	-	-
Convertible debentures (2)	148.5	62.3	-	-	-	86.2
Total contractual obligations	**$ 539.9**	**$ 71.8**	**$ 359.9**	**$ 11.1**	**$ 8.9**	**$ 88.2**

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

(2) As at March 31, 2011, Advantage had $148.5 million convertible debentures outstanding (excluding interest payable during the various debenture terms). Each series of convertible debentures are convertible to 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 shares at Advantage's option.

Liquidity and Capital Resources

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

($000, except as otherwise indicated)	**March 31, 2011**
Bank indebtedness (non-current)	$ 347,353
Working capital deficit (1)	44,582
Net debt	$ 391,935
Shares outstanding, representing shareholders' equity	164,555,585
Shares closing market price ($/share)	$ 8.70
Market capitalization (2)	$ 1,431,634
Convertible debentures maturity value (current and non-current)	$ 148,544
Total capitalization	**$ 1,972,113**

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

(2) Market capitalization is a non-IFRS measure.

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, bank indebtedness, convertible debentures, and shareholders' equity. 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. 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 current economic situation has placed considerable pressure on commodity prices. Natural gas prices have remained low throughout 2010 due to the weaker economy as well as high inventory levels with AECO gas presently trading at approximately \$3.70/mcf. However, crude oil has remained relatively strong during 2010 and near the end of 2010 began to increase and significantly escalated during early 2011, primarily influenced by middle-east civil unrest and associated supply concerns, with WTI currently trading at approximately US\$100/bbl. The outlook for the Corporation from prolonged weak natural gas prices would be reductions in operating netbacks and funds from operations. Management has partially mitigated this risk through our commodity hedging program but the lower natural gas price environment has still had a significant negative impact. 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 certain oil-weighted assets to Longview Oil Corp. with the net proceeds utilized to further repay bank indebtedness (see section "Creation of Longview Oil Corp."). 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 balance funds from operations and our capital program expenditure requirements. A successful hedging program was also executed to help reduce the volatility of funds from operations. However, we are still 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 March 31, 2011, the Corporation had 164.6 million shares outstanding. During 2011 we have issued 463,576 shares to employees in accordance with the vesting provisions of the RSPIP. As at May 12, 2011, shares outstanding have increased to 165.1 million.

The Corporation had \$148.5 million convertible debentures outstanding at March 31, 2011 that were immediately convertible to 13.0 million shares based on the applicable conversion prices (December 31, 2010 - \$148.5 million outstanding and convertible to 13.0 million shares). During the three months ended March 31, 2011, there were no conversions of debentures. As at May 12, 2011, the convertible debentures outstanding have not changed from December 31, 2010. We have \$62.3 million of 7.75% and 8.00% debentures that mature in December 2011 and \$86.2 million of 5.00% debentures that mature in January 2015. These obligations can be settled through the payment of cash or issuance of shares at Advantage's option.

Bank Indebtedness, Credit Facility and Other Obligations

At March 31, 2011, Advantage had bank indebtedness outstanding of \$347.4 million. Bank indebtedness increased \$56.7 million since December 31, 2010, primarily due to capital expenditures required to complete our Phase III development program at Glacier, Alberta. The Corporation's credit facility at March 31, 2011 was \$525 million, comprised of a \$20 million extendible revolving operating loan facility and a \$505 million extendible revolving loan facility (the "Credit Facilities"). The Credit Facilities are collateralized by a \$1 billion floating charge demand debenture covering all assets of the Corporation. As well, the borrowing base for the Corporation's credit facilities is determined through utilizing our 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. Revisions 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. As a result of the disposition of oil-weighted assets to Longview Oil Corp. that closed on April 14, 2011, the Advantage credit facility was reduced to $275 million (see section "Creation of Longview Oil Corp."). As of May 12, 2011, Advantage had bank indebtedness of approximately $120 million outstanding. The next annual review is scheduled to occur in June 2011. There can be no assurance that the $275 million credit facility will be renewed at the current borrowing base level at that time.

Advantage had a working capital deficiency of $44.6 million as at March 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 capital expenditure program. However, our working capital deficit decreased $19.9 million from December 31, 2010 as our Phase III development program at Glacier, Alberta concluded. We do not anticipate any problems in meeting future obligations as they become due given the level of our funds from operations. 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.

Capital Expenditures

	Three months ended March 31	
($000)	**2011**	**2010**
Drilling, completions and workovers	$ 62,665	$ 52,049
Well equipping and facilities	13,742	14,012
Land and seismic	306	2,084
Other	282	185
Expenditures on property, plant and equipment	76,995	68,330
Expenditures on exploration and evaluation assets	166	364
Property dispositions	-	(4,414)
Net capital expenditures (1)	**$ 77,161**	**$ 64,280**

(1) Net capital expenditures excludes changes in non-cash working capital.

Advantage's exploitation and development program is focused primarily at Glacier, Alberta where we are developing a significant natural gas resource play. Our preference is to operate a high percentage of our properties such that we can maintain control of capital expenditures, operations and cash flows. Advantage's acquisition strategy has been to acquire long-life properties with strong drilling opportunities while retaining a balance of year round access and risk.

For the three months ended March 31, 2011, the Corporation spent a net $77.2 million including $63.2 million at Glacier, $3.7 million at Nevis, $3.4 million at Brazeau, $2.9 million in Saskatchewan, and the remaining balance at other areas. However, we continue to focus on development of our Montney natural gas resource play at Glacier where Advantage will continue to employ a phased development approach. Phase II was completed during the second quarter of 2010. Construction of our facilities and gas gathering system expansions were completed ahead of schedule and on-budget leading to an earlier than anticipated commissioning of Advantage's 100% working interest gas plant in March 2010. Due to stronger than expected well performance, we were able to further increase Glacier production to exit 2010 at approximately 60 mmcf/d (10,000 boe/d). Our Phase III expansion began at the end of the second quarter of 2010 and included the drilling of 28 net (28 gross) horizontal wells and the fabrication of a new processing train to facilitate expansion of our Glacier gas plant to its current capacity of 100 mmcf/d. We currently have considerable production behind pipe from additional wells that will be brought on-stream as required to offset declines and maintain production. The amount of excess field production capacity above our current plant capacity is a result of our successful drilling program which demonstrated well test rates that exceeded expectations and proved up a large portion of our undrilled acreage at Glacier.

Sources and Uses of Funds

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

	Three months ended March 31	
($000)	**2011**	**2010**
Sources of funds		
Increase in bank indebtedness	$ 56,696	$ 6,997
Funds from operations	40,248	49,685
Other	615	4,175
Property dispositions	-	4,414
	$ 97,559	**$ 65,271**
Uses of funds		
Expenditures on property plant and equipment	$ 75,487	$ 59,567
Increase in working capital	20,800	3,083
Expenditures on decommissioning liability	1,038	1,392
Expenditures on exploration and evaluation	166	364
Reduction of capital lease obligations	68	555
Other	-	310
	$ 97,559	**$ 65,271**

Funds from operations decreased during the three months ended March 31, 2011 compared to 2010, due to reduced production attributed to asset dispositions and lower realized derivative gains from less natural gas production hedged for this year at lower average prices. However, funds from operations were positively impacted during 2011 from an improvement in crude oil prices and continued cost reduction efforts. Bank indebtedness increased in 2011 as would be expected due to our very active capital expenditure program that included finalizing our Glacier Phase III program that comprised expanding the Glacier gas plant and drilling 28 wells. We have focused on balancing our funds from operations and expenditures on property, plant and equipment to maintain a strong financial position and preserve financial flexibility.

Quarterly Performance

($000, except as otherwise indicated)	2011 Q1	2010 Q4	2010 Q3	2010 Q2	2010 Q1	2009 [(1)] Q4	2009 [(1)] Q3	2009 [(1)] Q2
Daily production								
Natural gas (mcf/d)	111,145	106,125	104,714	107,821	87,346	84,466	91,200	124,990
Crude oil and NGLs (bbls/d)	6,251	6,620	6,835	7,395	7,975	8,488	8,431	10,212
Total (boe/d)	24,775	24,308	24,287	25,365	22,533	22,566	23,631	31,044
Average prices								
Natural gas ($/mcf)								
Excluding hedging	$ 3.72	$ 3.49	$ 3.51	$ 3.81	$ 5.26	$ 4.28	$ 2.89	$ 3.56
Including hedging	$ 4.55	$ 4.81	$ 4.80	$ 5.58	$ 6.87	$ 6.90	$ 6.10	$ 5.63
AECO monthly index	$ 3.77	$ 3.58	$ 3.72	$ 3.86	$ 5.35	$ 4.18	$ 3.03	$ 3.66
Crude oil and NGLs ($/bbl)								
Excluding hedging	$ 75.41	$ 69.19	$ 61.84	$ 64.66	$ 67.23	$ 63.04	$ 56.99	$ 55.89
Including hedging	$ 72.82	$ 64.14	$ 59.01	$ 61.80	$ 62.42	$ 57.85	$ 54.02	$ 54.51
WTI ($US/bbl)	$ 94.25	$ 85.18	$ 76.21	$ 77.98	$ 78.79	$ 76.17	$ 68.29	$ 59.62
Total sales including realized hedging	$ 86,488	$ 86,012	$ 83,335	$ 96,377	$ 98,777	$ 98,782	$ 93,101	$ 114,659
Net income (loss)	$ (5,709)	$ (22,888)	$ (659)	$ 31,378	$ 33,089	$ (14,213)	$ (53,293)	$ (37,810)
per share - basic	$ (0.03)	$ (0.14)	$ -	$ 0.19	$ 0.20	$ (0.09)	$ (0.33)	$ (0.26)
- diluted	$ (0.03)	$ (0.14)	$ -	$ 0.19	$ 0.20	$ (0.09)	$ (0.33)	$ (0.26)
Funds from operations	$ 40,248	$ 40,813	$ 37,514	$ 45,290	$ 49,685	$ 50,083	$ 42,213	$ 51,590

(1) The financial and operating data for 2009 was prepared in accordance with the previous Canadian generally accepted accounting principles.

The table above highlights the Corporation's and Fund's performance for the first quarter of 2011 and also for the preceding seven quarters. Production was strong in the second quarter of 2009 due to increased production at Glacier. We experienced a significant decrease in production during the third quarter of 2009 as we completed asset dispositions that closed in July 2009. The disposed properties represented approximately 8,100 boe/d of production. Production in the fourth quarter of 2009 actually increased 3% from the prior quarter due to new production additions which was partially offset by some natural declines and cold weather conditions that typically cause production interruptions. In addition, an extended third party facility outage at our Lookout Butte property that began in 2008 resulted in 1,100 boe/d of reduced production that continued through much of 2009 but was completed and our production came back on in November 2009. 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 additional asset dispositions during the end of the second quarter of 2010 representing approximately 1,700 boe/d that resulted in lower production. The full impact of these recent dispositions resulted in a decrease in production for the third quarter of 2010 with our production remaining consistent during the fourth quarter of 2010 and increasing modestly in the first quarter of 2011 as the Phase III expansion at Glacier, Alberta was substantially completed at the end of the quarter. Our financial results, particularly sales and funds from operations, have declined since 2009, as commodity prices decreased in response to the financial crisis that materialized in the fall of 2008 and commodity prices continued on a downward trend through to the third quarter of 2009. We experienced improvements in commodity prices during the fourth quarter of 2009 and the first quarter of 2010 that increased our sales and funds from operations; however, natural gas prices still remained low. During the remainder 2010 and early 2011, natural gas prices have remained weak, which has decreased our corresponding sales and funds from operations. Weak commodity prices, particularly natural gas, have generally resulted in the recognized net losses for 2009 through 2011. Partially offsetting the net losses experienced during these periods has been the continuing reduction in costs including royalties and operating costs.

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 through depreciation and impairment of petroleum and natural gas properties. The reserve estimates are also used to assess the borrowing base for the Corporation's credit facilities. Revision or changes in the reserve estimates can have either a positive or a negative impact on net income and the borrowing base of the Corporation.

Management's process of determining the provision for deferred income taxes, the provision for decommissioning liability costs and related accretion expense, 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 petroleum and natural gas 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 and net 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 and foreign exchange rates 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 22 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 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.

IFRS 9 Financial Instruments: Classification and Measurement

IFRS 9 was issued in November 2009. This standard is the first step in the process to replace IAS 39 Financial Instruments: Recognition and Measurement. IFRS 9 introduces new requirements for classifying and measuring assets and liabilities, which may affect the Corporation's accounting for its financial assets. The standard is not applicable until January 1, 2013 but is available for early adoption. The Corporation has yet to assess the full impact of IFRS 9.

i) Internal Controls

In accordance with the Corporations approach to certification of internal controls required under Canadian Securities Administrators' National instrument 52-109 and SOX 302 and 404, all entity level, information technology, disclosures and business process controls will require updating and testing to reflect changes arising from our conversion to IFRS. Upon review with internal audit, we have determined there to be minimal updating of processes, controls and documentation required which is in progress.

Disclosure Controls and Internal Controls over Financial Reporting

Disclosure controls and procedures have been designed to provide reasonable assurance that information required to be disclosed by the Corporation is recorded, processed, summarized and reported within the time periods specified under the Canadian securities law. Advantage's Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation, that the disclosure controls and procedures as of the end of March 31, 2011, are effective and provide reasonable assurance that material information related to the Corporation is made known to them by others within Advantage.

Advantage's Chief Executive Officer and Chief Financial Officer are responsible for establishing and maintaining internal controls over financial reporting ("ICFR"). They have, as at the quarter ended March 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 ICFR is the Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations.

Advantage's Chief Executive Officer and Chief Financial Officer are required to disclose any change in the internal controls over financial reporting 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 period ended March 31, 2011 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

It should be noted that a control system, including Advantage's disclosure and internal controls and procedures, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

Creation of Longview Oil Corp.

On March 7, 2011 Advantage announced that Longview Oil Corp. ("Longview"), a wholly-owned subsidiary of the Corporation, filed a preliminary prospectus on March 4, 2011 for an initial public offering (the "Offering"), to raise gross proceeds of $172.5 million including an over-allotment option of up to 15% of the base offering size, exercisable 30 days following the closing of the Offering. The final prospectus was filed on April 6, 2011, the Offering closed on April 14, 2011 and the over-allotment option was exercised in full on April 28, 2011.

Longview was created to acquire certain oil-weighted assets (the "Acquired Assets") located in West Central Alberta, Southeast Saskatchewan and the Lloydminster area of Saskatchewan with fourth quarter 2010 average production of 6,220 boe/d (74% crude oil and NGLs, proved reserves of 20.1 mmboe and proved plus probable reserves of 36.9 mmboe, based on a report prepared by Sproule & Associates Limited on the Acquired Assets for Advantage and Longview with an effective date of December 31, 2010. Longview also assumed Advantage's remaining oil financial derivative contract fixing the price on 1,500 bbls/d of production at $91.05/bbl. Longview's business strategy is to provide shareholders with attractive long-term returns that combine both growth and yield by exploiting the Acquired Assets in a financially disciplined manner, acquiring additional long-life oil and gas assets of a similar nature and through the payment of a monthly dividend.

Concurrent with closing of the Offering, Longview purchased the Acquired Assets from Advantage (the "Transaction"), with consideration comprised of $245.5 million and 29,450,000 common shares of Longview. Advantage used the cash proceeds from the Transaction to reduce outstanding bank indebtedness.

Advantage has retained an equity ownership interest of approximately 63.1% of the common shares of Longview. Concurrent with closing of the Offering, 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.

As the disposition of the Acquired Assets to Longview occurred after March 31, 2011 and is not reflected within Advantage's financial and operating results for the current quarter, we have provided the following supplemental information summarizing production, operating income and expenditures on property, plant and equipment for the three months ended March 31, 2011 relating to the specific assets subsequently owned by each of Advantage and Longview.

	ADVANTAGE Three months ended March 31, 2011	**LONGVIEW** Three months ended March 31, 2011
Daily production		
Natural gas (mcf/d)	102,322	8,823
Crude oil (bbls/d)	526	4,011
NGLs (bbls/d)	1,126	588
Total (boe/d)	**18,705**	**6,070**
Natural gas (%)	91%	24%
Crude oil (%)	3%	66%
NGLs (%)	6%	10%

	ADVANTAGE Three months ended March 31, 2011		LONGVIEW Three months ended March 31, 2011	
	$000	per boe	$000	per boe
Sales				
Crude oil and NGLs	$ 10,805		$ 31,621	
Natural gas	34,011		3,195	
Total sales	44,816	$ 26.62	34,816	$ 63.73
Royalties	(4,564)	(2.71)	(6,862)	(12.56)
Royalty %	*10.2%*		*19.7%*	
Operating expense	(13,708)	(8.14)	(8,779)	(16.07)
Operating income	**$ 26,544**	**$ 15.77**	**$ 19,175**	**$ 35.10**
Realized gain (loss) on derivatives	7,104	4.22	(248)	(0.45)
Cash netback	**$ 33,648**	**$ 19.99**	**$ 18,927**	**$ 34.65**
Expenditures on property, plant and equipment	$ 66,603		$ 10,392	

For the three months ended March 31, 2011, production from the assets disposed to Longview was 6,070 boe/d, reflective of industry declines since the fourth quarter of 2010. During the first quarter of 2011, Advantage incurred production optimization expenditures including workovers that increased operating costs.

Advantage spent $10.4 million in the first quarter of 2011 related to the Longview assets, including the drilling of 6.8 net wells at a 100% success rate. Drilling activity included 3 net wells at Eyehill, 2 net wells at Nevis, 0.6 net wells at Alameda, and Cardium drilling activity at Brazeau/Ferrier. All of these wells have been cased and will be brought on production in the second quarter of 2011. With the creation of Longview, the capital expenditure program on these assets will accelerate along with other operating activities. We have contracted three rigs which will begin drilling subsequent to spring breakup. Two of the rigs will target Alberta prospects and the additional rig will target the Midale formation in southeast Saskatchewan.

As a result of the successful completion of the Transaction, historical financial and operating performance as well as forward-looking information may not be indicative of actual future performance.

Outlook

Phase III of our Glacier development project that began at the end of the second quarter of 2010 was completed at the end of the first quarter of 2011 on-budget and ahead of schedule with production capacity increasing to 100 mmcf/d (16,667 boe/d) resulting in a corporate exit daily production rate for this quarter of approximately 30,000 boe/d. Phase III of our Glacier development project included the drilling of 28 net (28 gross) horizontal wells and the fabrication of a new processing train to facilitate expansion of our Glacier gas plant to the current capacity of 100 mmcf/d. Upper Montney well results particularly in the eastern portion of our land block exceeded expectations resulting in surplus production capacity which will be brought on-stream as required to offset declines. For the second quarter of 2011, we anticipate production at Glacier will average approximately 90 to 95 mmcf/d due to pressure restrictions and scheduled compressor maintenance on the TransCanada transportation system.

Drilling results at our cornerstone Glacier property have demonstrated that our Montney development is among the top tier natural gas resource developments in North America. The attractive cost structure at Glacier which includes low operating costs and low royalty rates combined with a multi-decade drilling inventory provides a strong foundation to drive future development beyond current production. With the expansion of Glacier now completed, a review of well performance, facility capacity and actual costs will be undertaken by Advantage to assess the timing and capital requirements for the next phase of growth at Glacier. Advantage will provide additional corporate guidance and communicate future development plans on or about mid-year 2011.

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 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.

May 12, 2011

CONSOLIDATED FINANCIAL STATEMENTS

Consolidated Statement of Financial Position

(thousands of Canadian dollars) (unaudited)	Notes	March 31, 2011	December 31, 2010	January 1, 2010
			(note 22)	(note 22)
ASSETS				
Current assets				
Trade and other receivables	6	$ 41,692	$ 42,276	$ 54,531
Prepaid expenses and deposits		5,265	6,488	9,936
Derivative asset	5	18,090	25,157	30,829
Total current assets		**65,047**	**73,921**	**95,296**
Non-current assets				
Derivative asset	5	-	-	323
Exploration and evaluation assets	7	8,131	8,262	6,923
Property, plant and equipment	8	1,916,771	1,883,762	1,824,699
Total non-current assets		**1,924,902**	**1,892,024**	**1,831,945**
Total assets		**$ 1,989,949**	**$ 1,965,945**	**$ 1,927,241**
LIABILITIES				
Current liabilities				
Trade and other accrued liabilities		$ 91,539	$ 112,457	$ 113,062
Capital lease obligations		-	759	1,375
Convertible debentures	12	62,091	62,013	69,927
Derivative liability	5	5,608	2,367	12,755
Total current liabilities		**159,238**	**177,596**	**197,119**
Non-current liabilities				
Derivative liability	5	-	177	1,165
Capital lease obligations		-	-	759
Bank indebtedness	11	346,365	288,852	247,784
Convertible debentures	12	73,570	72,811	131,561
Decommissioning liability	14	161,027	172,130	169,665
Deferred income tax liability		38,873	40,231	22,115
Other liability	15	1,609	1,835	3,431
Total non-current liabilities		**621,444**	**576,036**	**576,480**
Total liabilities		**780,682**	**753,632**	**773,599**
SHAREHOLDERS' EQUITY				
Share capital	9	2,202,526	2,199,491	2,190,409
Convertible debentures equity component	12	8,348	8,348	8,348
Contributed surplus		14,411	14,783	6,114
Deficit		(1,016,018)	(1,010,309)	(1,051,229)
Total shareholders' equity		**1,209,267**	**1,212,313**	**1,153,642**
Total liabilities and shareholders' equity		**$ 1,989,949**	**$ 1,965,945**	**$ 1,927,241**

Commitments (note 20)
Subsequent events (note 21)
See accompanying Notes to the Interim Consolidated Financial Statements

Consolidated Statement of Comprehensive Income (Loss)

(thousands of Canadian dollars, except for per share amounts) (unaudited)	Notes		Three months ended March 31, 2011		Three months ended March 31, 2010 (note 22)
Petroleum and natural gas sales		$	79,632	$	89,560
Less: royalties			(11,426)		(13,189)
Petroleum and natural gas revenue			68,206		76,371
Operating expense			(22,487)		(23,606)
General and administrative expense	17		(8,356)		(9,466)
Depreciation expense	8		(32,406)		(28,229)
Exploration and evaluation expense	7		(205)		-
Gains (losses) on derivatives	5		(3,275)		35,328
Other income	16		101		4,543
Operating income before finance and taxes			**1,578**		**54,941**
Finance expense	18		(8,645)		(9,651)
Income (loss) before taxes			**(7,067)**		**45,290**
Income tax recovery (expense)	19		1,358		(12,201)
Net income (loss) and comprehensive income (loss)		**$**	**(5,709)**	**$**	**33,089**
Net income (loss) per share	10				
Basic		**$**	**(0.03)**	**$**	**0.20**
Diluted		**$**	**(0.03)**	**$**	**0.20**

See accompanying Notes to the Interim Consolidated Financial Statements

Consolidated Statement of Changes in Shareholders' Equity

(thousands of Canadian dollars) (unaudited)	Notes	Share capital	Convertible debentures equity component	Contributed surplus	Deficit	Total shareholders' equity
Balance, January 1, 2011		$ 2,199,491	$ 8,348	$ 14,783	$ (1,010,309)	$ 1,212,313
Share based compensation	13	3,035	-	(372)	-	2,663
Net loss and comprehensive loss		-	-	-	(5,709)	(5,709)
Balance, March 31, 2011		$ 2,202,526	$ 8,348	$ 14,411	$ (1,016,018)	$ 1,209,267
Balance, January 1, 2010	22	$ 2,190,409	$ 8,348	$ 6,114	$ (1,051,229)	$ 1,153,642
Share based compensation	13	2,089	-	1,254	-	3,343
Net income and comprehensive income		-	-	-	33,089	33,089
Balance, March 31, 2010		$ 2,192,498	$ 8,348	$ 7,368	$ (1,018,140)	$ 1,190,074

See accompanying Notes to the Interim Consolidated Financial Statements

Consolidated Statement of Cash Flows

(thousands of Canadian dollars) (unaudited)	Notes	Three months ended March 31, 2011	Three months ended March 31, 2010
			(note 22)
Operating Activities			
Operating income before finance and taxes		$ 1,578	$ 54,941
Add (deduct) items not requiring cash:			
Share based compensation	13	2,175	3,751
Depreciation expense	8	32,406	28,229
Exploration and evaluation expense	7	205	-
Unrealized loss (gain) on derivatives	5	10,131	(26,111)
Gain on sale of property, plant and equipment	16	(76)	(4,037)
Expenditures on decommissioning liability	14	(1,038)	(1,392)
Changes in non-cash working capital		(20,800)	(3,083)
Cash provided by operating activities		**24,581**	**52,298**
Financing Activities			
Increase in bank indebtedness	11	56,696	6,997
Reduction of capital lease obligations		(68)	(555)
Convertible debenture issue costs		-	(310)
Interest paid		(5,556)	(2,913)
Cash provided by financing activities		**51,072**	**3,219**
Investing Activities			
Expenditures on property, plant and equipment	8	(75,487)	(59,567)
Expenditures on exploration and evaluation assets	7	(166)	(364)
Property dispositions		-	4,414
Cash used in investing activities		**(75,653)**	**(55,517)**
Net change in cash		-	-
Cash, beginning of period		-	-
Cash, end of period		$ -	$ -

See accompanying Notes to the Interim Consolidated Financial Statements

March 31, 2011 (unaudited)

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

1. Business and structure of Advantage

Advantage Oil & Gas Ltd. and its subsidiaries (together "Advantage" or the "Corporation") is 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.

2. Basis of preparation

(a) Statement of compliance

The March 31, 2011 interim consolidated financial statements are Advantage's first financial statements prepared under International Financial Reporting Standards ("IFRS"), with a transition date to IFRS of January 1, 2010. As a result, the comparative figures for 2010 and Advantage's financial position as at January 1, 2010 have been restated from Canadian Generally Accepted Accounting Principles ("Previous GAAP") to IFRS. The reconciliations to IFRS from Previous GAAP are summarized in note 22 and discloses 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 22, 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 interim consolidated financial statements of Advantage have been prepared by management in accordance with IAS 34 – Interim Financial Reporting and are in accordance with IFRS 1 – First-time Adoption of IFRS, as they are part of the year ending December 31, 2011, the fiscal period of the Corporation's first IFRS financial statements.

The policies applied in these condensed interim consolidated financial statements are based on IFRS issued and outstanding as of May 12, 2011, the date the Board of Directors approved the statements. Any changes to IFRS that occur subsequent to May 12, 2011 will be reflected in the Corporation's future interim and annual consolidated financial statements and could result in restatement of these interim consolidated financial statements, including the transition adjustments recognized on change-over to IFRS.

The interim consolidated financial statements should be read in conjunction with the Corporation's Previous GAAP annual financial statements for the year ended December 31, 2010. Note 22 discloses IFRS information for the year ended December 31, 2010 that is material to an understanding of these interim consolidated financial statements.

(b) Basis of measurement

The consolidated financial statements have been prepared on the historical cost basis, except for derivative instruments, which are measured at fair value.

The methods used to measure fair values of derivative instruments are discussed in note 5.

(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. All inter-corporate balances, income and expenses resulting from inter-corporate transactions are eliminated.

3. 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 5 – valuation of financial instruments;
- Note 8 – valuation of property, plant and equipment;
- Note 8 – impairment;
- Note 5, 12 – valuation of convertible debentures;
- Note 13 – measurement of share-based compensation; and
- Note 14 – measurement of decommissioning liability.

Judgements

In the process of applying the Corporation's accounting policies, management has made the following judgements, 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 are in close proximity to existing or established development and production properties (either of the Corporation or another industry participant), 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 are classified as exploration and evaluation assets.

3. Significant accounting judgments, estimates and assumptions (continued)

(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, the latter having an impact on the proportion of the gross reserves which are attributable to provincial governments under respective royalty frameworks. 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.

(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. This would generally result from significant changes in any of the factors or assumptions used in estimating reserves. These factors could include:

- Changes in proved plus probable reserves.
- The effect on proved plus probable reserves of differences between actual commodity prices and commodity price assumptions.
- The effect on proved plus probable reserves of differences between the estimated and actual future costs to develop the proved and probable reserves of any properties not developed at the time reserves are estimated.
- The effect on proved plus probable reserves of differences between estimated and actual royalties paid in future periods.
- The effect on proved plus probable reserves of differences between actual and estimated future costs associated with well site and facility abandonment.
- Unforeseen operational issues.

(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 clearly indicate 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, including the discount rate applied.

3. Significant accounting judgments, estimates and assumptions (continued)

(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.

4. Significant accounting policies

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

4. Significant accounting policies (continued)

(ii) Jointly controlled assets

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

The Corporation's financial instruments consist of financial assets, financial liabilities, and non-financial derivatives. 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 other financial liabilities. 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 other financial liabilities are recognized at amortized cost using the effective interest method and impairment losses are recorded in income when incurred. With all new financial instruments, an election is available that allows entities to classify any financial instrument as fair value through profit or loss. Only those financial assets and liabilities that must be classified as fair value through profit or loss are classified as such by the Corporation.

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 consolidated statement of comprehensive income 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.

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.

4. Significant accounting policies (continued)

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

(i) Recognition and measurement

The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of the decommissioning obligation, and for qualifying assets, borrowing costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. The capitalized value of a finance lease is also included within property, plant and equipment.

a) Exploration and evaluation expenditures

Pre-license costs are recognized in the statement of operations as incurred.

All exploratory costs incurred subsequent to acquiring the right to explore for oil and natural gas are capitalized. 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.

Exploration and evaluation costs initially are capitalized as either tangible or intangible exploration or evaluation assets according to the nature of the assets acquired. The costs are accumulated in cost centers by well, field or exploration area pending determination of technical feasibility and commercial viability.

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. For purposes of impairment testing, exploration and evaluation assets are allocated to cash-generating units.

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. A review of each exploration license or field is carried out, at least annually, to ascertain whether proved and probable reserves have been discovered. 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. If the well or exploration project did not encounter potentially economic oil and gas quantities, the costs are expensed and reported in exploration and evaluation expense in the period incurred.

b) Development and production costs

Items of property, plant and equipment, which include oil and gas development and production assets, are measured at cost (including directly attributable general and administrative costs) 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 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).

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 disposal 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.

4. 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 comprehensive income 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.

Proved and probable reserves are estimated using independent reserve engineer reports and represent the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. 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. 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.

Such reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon:

- a reasonable assessment of the future economics of such production;
- a reasonable expectation that there is a market for all or substantially all the expected oil and natural gas production; and
- evidence that the necessary production, transmission and transportation facilities are available or can be made available.

Reserves may only be considered proved and probable if producibility is supported by either actual production or conclusive formation test. The area of reservoir considered proved and probable includes (a) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, or both, and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geophysical, geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of oil and natural gas controls the lower proved limit of the reservoir.

Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are only included in the proved and probable classification when successful testing by a pilot project, the operation of an installed program in the reservoir, or other reasonable evidence (such as, experience of the same techniques on similar reservoirs or reservoir simulation studies) provides support for the engineering analysis on which the project or program was based.

The Corporation records furniture and equipment at cost and provides depreciation on the declining balance method at a rate of 20% per annum which is designed to amortize the cost of the assets over their estimated useful lives. The Corporation records leasehold improvements at cost and provides depreciation on the straight-line method over the term of the lease. Leased assets are depreciated over the shorter of the lease term and their useful lives unless it is reasonably certain that the Corporation will obtain ownership by the end of the lease term. Depreciation methods, useful lives and residual values are reviewed at each reporting date.

4. Significant accounting policies (continued)

(e) Asset swaps

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 comprehensive income.

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

(f) Leased assets

Leases where the Corporation assumes substantially all the risks and rewards of ownership are classified as finance leases. Upon initial recognition the leased asset is measured at an amount equal to the lower of its fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset.

Minimum lease payments made under finance leases are apportioned between the finance expenses and the reduction of the outstanding liability. The finance expenses are allocated to each year during the lease term so as to produce a constant periodic rate of interest on the remaining balance of the liability.

Other leases are operating leases, which are not recognized on the Corporation's statement of financial position.

Payments made under operating leases are recognized in comprehensive income on a straight-line basis over the term of the lease. Lease incentives received are recognized as part of the total lease expense, over the term of the lease.

(g) Impairment

(i) Financial assets

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in income.

An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in comprehensive income.

4. Significant accounting policies (continued)

(g) Impairment (continued)

(ii) Non-financial assets

The carrying amounts of the Corporation's non-financial assets, other than exploration and evaluation assets and deferred income tax assets, 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 goodwill and other intangible assets that have indefinite lives or that are not yet available for use, an impairment test is completed each year. Exploration and evaluation assets are assessed for impairment when they are reclassified to property, plant and equipment, as oil and natural gas interests, and also if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purpose of impairment testing, 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"). 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.

Any goodwill acquired in a business combination, for the purpose of impairment testing, is allocated to the CGU's that are expected to benefit from the synergies of the combination. Exploration and evaluation assets are allocated to related CGU's when they are assessed for impairment, both at the time of any triggering facts and circumstances as well as upon their eventual reclassification to producing assets (oil and natural gas interests in property, plant and equipment).

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in income. Impairment losses recognized in respect of CGU's are allocated first to reduce the carrying amount of any goodwill allocated to the units and then to reduce the carrying amounts of the other assets in the unit (group of units) on a pro rata basis.

An impairment loss in respect of goodwill is not reversed. In respect of other assets, 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 or amortization, if no impairment loss had been recognized.

(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 of the Corporation, including directors, officers, employees, and consultants. The restricted share grants generally vest one-third immediately on grant date, with the remaining two-thirds vesting evenly on the following two yearly anniversary dates. Compensation cost related to the Plan is recognized as compensation expense within general and administrative expense over the service period and incorporates the share grant price, 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.

4. Significant accounting policies (continued)

(i) 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. Decommissioning liabilities are not recognized for future operating losses.

(j) Revenue

Revenue from the sale of oil 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. With respect to the latter, the entity is acting as a collection agent on behalf of others.

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

(k) Finance expenses

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

(l) Borrowing costs capitalized

Borrowing costs incurred for the construction of qualifying assets are capitalized during the period of time that is required to complete and prepare the assets for their intended use or sale. The Corporation considers a qualifying asset to be any significant construction project expected to take more than twelve months to complete. The capitalization rate used to determine the amount of borrowing costs to be capitalized is the weighted average interest rate applicable to the Corporation's outstanding general and specific borrowings during the period.

(m) 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.

4. Significant accounting policies (continued)

(n) Net income per share

Basic net income per share is calculated by dividing the net income attributable to common shareholders of the Corporation by the weighted average number of common shares outstanding during the period. Diluted net income per share is determined by adjusting the net income 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 employees, and convertible debentures.

(o) 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.

IFRS 9 Financial Instruments: Classification and Measurement

IFRS 9 was issued in November 2009. This standard is the first step in the process to replace IAS 39 *Financial Instruments: Recognition and Measurement.* IFRS 9 introduces new requirements for classifying and measuring assets and liabilities, which may affect the Corporation's accounting for its financial assets. The standard is not applicable until January 1, 2013 but is available for early adoption. The Corporation has yet to assess the full impact of IFRS 9.

5. 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 other liabilities and similarly measured at amortized cost. As at March 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 other liabilities and measured 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 March 31, 2011, the estimated fair value of the total outstanding convertible debenture obligation was $167.4 million (December 31, 2010 - $153.2 million). The fair value of the liability component of convertible debentures was determined based on a discounted cash flow model assuming no future conversions and continuation of current interest and principal payments as well as taking into consideration the current public trading activity of such debentures. The Corporation applied discount rates of between 4% and 9% considering current available market information, assumed credit adjustments, and various terms to maturity.

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.

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.

5. Financial risk management (continued)

Advantage has an established strategy to manage the risk associated with changes in commodity prices by entering into non-financial derivatives, which are recorded at fair value as derivative assets and liabilities with gains and losses recognized through comprehensive income. As the fair value of the contracts varies with commodity prices, they give rise to financial assets and liabilities. The fair values of the derivatives are determined by a Level 2 valuation model, where pricing inputs other than quoted prices in an active market are used. These 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 and foreign exchange rates as compared to the valuation assumptions.

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

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

(a) Credit risk

Credit risk is the risk of financial loss to the Corporation if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Corporation's receivables from joint venture partners and oil and natural gas marketers. The maximum exposure to credit risk at year-end is as follows:

		March 31, 2011		December 31, 2010		January 1, 2010
Trade and other receivables	$	41,692	$	42,276	$	54,531
Deposits		2,936		2,936		6,108
Derivative asset		18,090		25,157		31,152
	$	**62,718**	**$**	**70,369**	**$**	**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 national 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 March 31, 2011, $2.1 million or 4.9% 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 that the entire balance is collectible, and in some instances we have the ability to mitigate risk through withholding production or offsetting payables with the same parties. Management has provided for an allowance for doubtful accounts of $0.2 million at March 31, 2011 (December 31, 2010 - $0.2 million).

The Corporation's most significant customer, a Canadian oil and natural gas marketer, accounts for $14.3 million of the trade and other receivables at March 31, 2011 (December 31, 2010 - $12.1 million).

5. 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, and derivative liabilities are primarily due within one year of the balance sheet date and Advantage does not anticipate any problems in satisfying the obligations from cash provided by operating activities and the existing credit facility. The Corporation's bank indebtedness is subject to a $525 million credit facility agreement. Although the credit facility is a source of liquidity risk, the facility also mitigates liquidity risk by enabling Advantage to manage interim cash flow fluctuations. The credit facility constitutes a revolving facility for a 364 day term which is extendible annually for a further 364 day revolving period at the option of the syndicate. If not extended, the revolving credit facility is converted to a one year term facility with the principal payable at the end of such one year term. The terms of the credit facility are such that it provides 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 several series of convertible debentures outstanding that mature from 2011 to 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 March 31, 2011 are as follows:

		Less than one year	One to three years	Four to five years	Thereafter	Total
Trade and other accrued liabilities		$ 91,539	$ -	$ -	$ -	$ 91,539
Derivative liability		5,608	-	-	-	5,608
Other liability		1,609	-	-	-	1,609
Bank indebtedness	- principal	-	347,353	-	-	347,353
	- interest	17,199	3,947	-	-	21,146
Convertible debentures	- principal	62,294	-	86,250	-	148,544
	- interest	9,179	8,625	4,313	-	22,117
		$ 187,428	**$ 359,925**	**$ 90,563**	**$ -**	**$ 637,916**

The Corporation's bank indebtedness does not have specific maturity dates. It is governed by a credit facility agreement with a syndicate of financial institutions (note 11). Under the terms of the agreement, the facility is reviewed annually, with the next review scheduled in June 2011. The facility is revolving, and is extendible at each annual review for a further 364 day period at the option of the syndicate. If not extended, the credit facility is converted at that time into a one year term facility, with the principal payable at the end of such one year term. Management fully expects that the facility will be extended at each annual review.

5. Financial risk management (continued)

(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% increase in the forward natural gas prices used to calculate the fair value of the natural gas derivatives at March 31, 2011 could decrease earnings by approximately $2.0 million for the three months ended March 31, 2011. As well, an increase of 10% in the forward crude oil prices used to calculate the fair value of the crude oil derivatives at March 31, 2011 could decrease earnings by $3.1 million for the three months ended March 31, 2011. A similar increase in the currency rate assumption underlying the derivatives fair value does not materially decrease earnings.

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

Description of Derivative	Term	Volume	Average Price
Natural gas - AECO			
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	January 2011 to December 2011	1,500 bbls/d	Cdn $91.05/bbl

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

5. Financial risk management (continued)

As at March 31, 2011, the fair value of the derivatives outstanding resulted in an asset of approximately $18.1 million (December 31, 2010 – $25.2 million) and a liability of approximately $5.6 million (December 31, 2010 – $2.5 million).

For the three months ended March 31, 2011, $3.3 million was recognized in net loss as a derivative loss (March 31, 2010 - $35.3 million derivative gain). The table below summarizes the realized and unrealized gains (losses) on derivatives.

		Three months ended March 31, 2011		Three months ended March 31, 2010
Realized gains on deriviatives	$	6,856	$	9,217
Change in unrealized gains (losses) on derivatives		(10,131)		26,111
	$	**(3,275)**	**$**	**35,328**

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 loan 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 100 basis points higher throughout the three months ended March 31, 2011, net loss would have increased by $0.6 million (March 31, 2010 - $0.5 million) based on the average debt balance outstanding during the period.

5. 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, capital lease obligations 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. The capital structure is reviewed by Management and the Board of Directors on an ongoing basis. Advantage's capital structure as at March 31, 2011, December 31, 2010 and January 1, 2010 is as follows:

	March 31, 2011	December 31, 2010	January 1, 2010
Bank indebtedness (non-current)	$ 347,353	$ 290,657	$ 250,262
Working capital deficit (1)	44,582	64,452	49,970
Net debt	391,935	355,109	300,232
Market capitalization (2)	1,431,634	1,109,262	1,122,944
Convertible debentures maturity value	148,544	148,544	218,471
Capital lease obligations (non-current)	-	-	759
Total capitalization	**$ 1,972,113**	**$ 1,612,915**	**$ 1,642,406**

(1) Working capital deficit is a non-IFRS measure that includes trade and other receivables, prepaid expenses and deposits, trade and other accrued liabilities, and the current portion of capital lease obligations.

(2) Market capitalization is a non-IFRS measure.

The Corporation's bank indebtedness is governed by a $525 million credit facility agreement (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 three months ended March 31, 2011.

6. Trade and other receivables

	March 31, 2011	December 31, 2010	January 1, 2010
Trade receivables	$ 33,069	$ 30,997	$ 31,608
Receivables from joint venture partners	5,942	6,296	13,719
Other	2,681	4,983	9,204
	$ 41,692	**$ 42,276**	**$ 54,531**

7. 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	166
Transferred to property, plant and equipment	(92)
Exploration and evaluation expense	(205)
Balance at March 31, 2011	**$ 8,131**

8. 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 decomissioning liability		37,073		-		37,073
Disposals		(60,482)		-		(60,482)
Balance at December 31, 2010	**$**	**2,018,949**	**$**	**4,024**	**$**	**2,022,973**
Additions		76,713		282		76,995
Change in decomissioning liability		(11,672)		-		(11,672)
Transferred from exploration and evaluation assets		92		-		92
Balance at March 31, 2011	**$**	**2,084,082**	**$**	**4,306**	**$**	**2,088,388**

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 loss		17,500		-		17,500
Disposals		(2,881)		-		(2,881)
Balance at December 31, 2010	**$**	**137,979**	**$**	**1,232**	**$**	**139,211**
Depreciation		32,252		154		32,406
Disposals		-		-		-
Balance at March 31, 2011	**$**	**170,231**	**$**	**1,386**	**$**	**171,617**

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 March 31, 2011	$	1,913,851	$	2,920	$	1,916,771

During the period ended December 31, 2010, Advantage recognized an impairment loss of $17.5 million. The loss relates to a cash generating unit which incurred a decline in recoverable amount based on a fair value less costs to sell determination. For the three months ended March 31, 2011, no impairment losses were recorded (March 31, 2010 - $Nil).

During the period ended March 31, 2011, Advantage capitalized general and administrative expenditures directly related to development activities of $1.8 million (March 31, 2010 - $2.3 million).

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

9. 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	1,346,481	9,082
Balance at December 31, 2010	164,092,009	$ 2,199,491
Share based compensation	463,576	3,035
Balance at March 31, 2011	164,555,585	$ 2,202,526

10. Net income (loss) per share

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

	Three months ended March 31, 2011	Three months ended March 31, 2010
Net income (loss)		
Basic and diluted	$ (5,709)	$ 33,089
Weighted average shares outstanding		
Basic	164,488,635	163,020,703
RSPIP	-	790,703
Diluted	164,488,635	163,811,406

The calculation of diluted net income (loss) per share excludes all series of convertible debentures as the impact would be anti-dilutive. Total weighted average shares issuable in exchange for the convertible debentures and excluded from the diluted net income (loss) per share calculation for the three months ended March 31, 2011 was 13,019,819 shares (March 31, 2010 – 15,821,382 shares). As at March 31, 2011, the total convertible debentures outstanding were immediately convertible to 13,019,819 shares (March 31, 2010 – 15,821,382 shares).

Restricted shares have been excluded from the calculation of diluted net income (loss) per share for the three months ended March 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 income (loss) per share calculation for the three months ended March 31, 2011 was 1,052,183.

11. Bank indebtedness

	March 31, 2011	December 31, 2010	January 1, 2010
Revolving credit facility	$ 347,353	$ 290,657	$ 250,262
Discount on Bankers Acceptances and other fees	(988)	(1,805)	(2,478)
Balance, end of period	**$ 346,365**	**$ 288,852**	**$ 247,784**

Advantage's credit facilities of $525 million is comprised of a $20 million extendible revolving operating loan facility from one financial institution and a $505 million extendible revolving loan facility from a syndicate of financial institutions (the "Credit Facilities"). 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 1.25% and 3.75% depending on the type of borrowing and the Corporation's debt to cash flow ratio. The Credit Facilities are collateralized by a $1 billion floating charge demand debenture covering all assets of the Corporation. The amounts available to Advantage from time to time under the Credit Facilities are based upon the borrowing base determined semi-annually by the lenders. The revolving period for the Credit Facilities will end in June 2011 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. The Credit Facilities contain standard commercial covenants for credit 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. This covenant was met at March 31, 2011 and December 31, 2010. Breach of any covenant will result in an event of default in which case Advantage 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 three months ended March 31, 2011, the average effective interest rate on the outstanding amounts under the facility was approximately 5.5% (March 31, 2010 – 5.3%). Advantage also has issued letters of credit totaling $3.7 million at March 31, 2011 (March 31, 2010 – $6.4 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 March 31, 2011 and changes in the liability and equity components during the period ended March 31, 2011 and year ended December 31, 2010 are as follows:

	6.50%	7.75%
Trading symbol	AAV.DBE	AAV.DBD
Debentures outstanding	$ -	$ 46,766
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	-	78
Balance at March 31, 2011	**$ -**	**$ 46,563**

	8.00%	5.00%	Total
Trading symbol	AAV.DBG	AAV.DBH	
Debentures outstanding	$ 15,528	$ 86,250	$ 148,544
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	-	759	837
Balance at March 31, 2011	**$ 15,528**	**$ 73,570**	**$ 135,661**
Equity component:			
Balance at January 1, 2010	**$ -**	**$ 8,348**	**$ 8,348**
Balance at December 31, 2010	**$ -**	**$ 8,348**	**$ 8,348**
Balance at March 31, 2011	**$ -**	**$ 8,348**	**$ 8,348**

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 three months ended March 31, 2011.

13. Share based compensation

Advantage has a Restricted Share Performance Incentive Plan ("RSPIP" or the "Plan") as approved by the shareholders on July 9, 2009, concurrent with the conversion to a corporation. The Plan authorizes the Board of Directors to grant restricted shares to service providers of the Corporation, including directors, officers, employees, and consultants. 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. 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 evenly on the following two yearly anniversary dates. 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 summarizes information about restricted shares outstanding at March 31, 2011:

Date Granted	Restricted Shares Granted	Restricted Shares Vested	Restricted Shares Forfeited	Restricted Shares Outstanding	Weighted average fair value at grant date
January 15, 2009	691,178	668,910	22,268	-	$5.49
September 2, 2009	1,453,609	743,858	15,119	694,632	$5.80
October 15, 2009	1,153,314	776,435	9,449	367,430	$7.51
January 12, 2010	779,013	522,690	6,754	249,569	$7.27
April 12, 2010	979,915	334,783	11,317	633,815	$6.97
July 12, 2010	788,092	264,167	5,527	518,398	$6.53
January 12, 2011	67,343	22,575	412	44,356	$6.95
Total	5,912,464	3,333,418	70,846	2,508,200	$6.60

14. 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 2011 and 2071. A risk-free rate of 3.72% (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:

		Three months ended March 31, 2011		**Year ended December 31, 2010**
Balance, beginning of period	$	172,130	$	169,665
Accretion expense		1,607		6,094
Liabilities incurred		573		3,331
Change in estimates		(864)		6,601
Effect of change in risk-free rate		(11,381)		27,141
Property dispositions		-		(34,427)
Liabilities settled		(1,038)		(6,275)
Balance, end of period	**$**	**161,027**	**$**	**172,130**

15. 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 2014. 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:

	Three months ended March 31, 2011	Year ended December 31, 2010
Balance, beginning of period	$ 1,835	$ 3,431
Accretion expense	30	199
Reduction of liability by subleasing space	-	(538)
Liability settled	(256)	(1,257)
Balance, end of period	**$ 1,609**	**$ 1,835**

16. Other income

	Three months ended March 31, 2011	Three months ended March 31, 2010
Gain on sale of property, plant and equipment	$ 76	$ 4,037
Miscellaneous income	25	506
Total other income	**$ 101**	**$ 4,543**

17. General and administrative expense

	Three months ended March 31, 2011	Three months ended March 31, 2010
Salaries and benefits	$ 4,582	$ 4,443
Share-based compensation	2,175	3,751
Office rent	658	606
Other	941	666
Total general and administration expense	**$ 8,356**	**$ 9,466**

18. Finance expense

	Three months ended March 31, 2011	Three months ended March 31, 2010
Interest on bank indebtedness	$ 3,908	$ 3,704
Interest on convertible debentures	2,263	3,384
Accretion on convertible debentures	837	804
Accretion of decomissioning liability	1,607	1,701
Accretion of other liability	30	58
Total finance expense	$ 8,645	$ 9,651

19. Income tax expense

Income tax expense is recognized based on management's best estimate of the weighted average annual income tax rate expected for the full financial year. The estimated average annual rate used for the three months ended March 31, 2011 was 26.67% (March 31, 2010 – 28.15%)

20. Operating leases

Advantage has several lease commitments relating to office buildings and transportation. The estimated remaining annual minimum operating lease payments are as follows, of which $1.6 million is recognized in other liability (note 15):

2011	$ 9,492
2012	12,477
2013	11,056
2014	8,901
2015	2,033
	$ 43,959

21. Subsequent events

On March 7, 2011 Advantage announced that Longview Oil Corp. ("Longview"), a wholly-owned subsidiary of the Corporation, filed a preliminary prospectus on March 4, 2011 for an initial public offering (the "Offering"), to raise gross proceeds of $172.5 million including an over-allotment option of up to 15% of the base offering size, exercisable 30 days following the closing of the Offering. The final prospectus was filed on April 6, 2011, the Offering closed on April 14, 2011 and the over-allotment option was exercised in full on April 28, 2011.

Concurrent with closing of the Offering, Longview purchased certain assets from Advantage (the "Transaction"), with consideration comprised of $245.5 million and 29,450,000 common shares of Longview. Advantage used the cash proceeds from the Transaction to reduce outstanding bank indebtedness. As a result of the disposition, the Advantage credit facility was reduced to $275 million with the next annual review scheduled to occur in June 2011.

22. 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 Canadian generally accepted accounting principles ("Previous GAAP"). These financial statements, for the interim period ended March 31, 2011, are the first prepared in accordance with International Financial Reporting Standards ("IFRS"). 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.

22. Transition to IFRS (continued)

Reconciliation of consolidated statement of financial position at the date of IFRS transition, January 1, 2010.

(thousands of Canadian dollars) (unaudited)	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**

22. Transition to IFRS (continued)

Reconciliation of consolidated statement of financial position at the end of the comparative interim period, March 31, 2010.

(thousands of Canadian dollars)(unaudited)	Notes	Previous GAAP	Effect of Transition to IFRS	IFRS Reclassifications	IFRS
ASSETS					
Current assets					
Trade and other receivables		$ 46,828	$ -	$ -	$ 46,828
Prepaid expenses and deposits		9,867	-	-	9,867
Derivative asset		43,956	-	-	43,956
Total current assets		**100,651**	**-**	**-**	**100,651**
Non-current assets					
Derivative asset		9,623	-	-	9,623
Exploration and evaluation assets	2	-		7,287	7,287
Property, plant and equipment	1,2,3	1,845,724	25,964	(7,287)	1,864,401
Total non-current assets		**1,855,347**	**25,964**	**-**	**1,881,311**
Total assets		**$ 1,955,998**	**$ 25,964**	**$ -**	**$ 1,981,962**
LIABILITIES					
Current liabilities					
Trade and other accrued liabilities	6	$ 113,100	$ -	$ 1,569	$ 114,669
Capital lease obligations		888	-	-	888
Convertible debentures	4	69,739	(12)	-	69,727
Derivative liability		10,236	-	-	10,236
Deferred income tax liability	5	9,199	-	(9,199)	-
Total current liabilities		**203,162**	**(12)**	**(7,630)**	**195,520**
Non-current liabilities					
Capital lease obligations		691	-	-	691
Bank indebtedness		255,682	-	-	255,682
Convertible debentures	4	131,576	989	-	132,565
Decommissioning liability	3	68,350	101,602	-	169,952
Deferred income tax liability	5	40,663	(15,547)	9,199	34,315
Other liability		3,163	-	-	3,163
Total non-current liabilities		**500,125**	**87,044**	**9,199**	**596,368**
Total liabilities		**703,287**	**87,032**	**1,569**	**791,888**
SHAREHOLDERS' EQUITY					
Share capital		2,192,498	-	-	2,192,498
Convertible debentures equity component	4	18,867	(10,519)	-	8,348
Contributed surplus	6	8,937	-	(1,569)	7,368
Deficit		(967,591)	(50,549)	-	(1,018,140)
Total shareholders' equity		**1,252,711**	**(61,068)**	**(1,569)**	**1,190,074**
Total liabilities and shareholders' equity		**$ 1,955,998**	**$ 25,964**	**$ -**	**$ 1,981,962**

22. Transition to IFRS (continued)

Reconciliation of consolidated statement of comprehensive income for the three months ended March 31, 2010:

(thousands of Canadian dollars)(unaudited)	Notes	Previous GAAP	Effect of Transition to IFRS	IFRS Reclassifications	IFRS
Petroleum and natural gas sales		$ 89,560	$ -	$ -	$ 89,560
Less: royalties	8	(12,858)	-	(331)	(13,189)
Petroleum and natural gas revenue		76,702	-	(331)	76,371
Operating expense	1c	(22,716)	(890)	-	(23,606)
General and administrative expense	1c	(9,195)	(271)	-	(9,466)
Depreciation expense	1b,7	(52,021)	22,584	1,208	(28,229)
Gains on derivatives		35,328	-	-	35,328
Other income	1a	-	4,543	-	4,543
Operating income before finance and taxes		**28,098**	**25,966**	**877**	**54,941**
Finance expense	3,4,7	(8,250)	(193)	**(1,208)**	(9,651)
Income before taxes		**19,848**	**25,773**	**(331)**	**45,290**
Income tax expense	5,8	(6,693)	(5,839)	331	(12,201)
Net income and comprehensive income		**$ 13,155**	**$ 19,934**	**$ -**	**$ 33,089**

22. 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)(unaudited)	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**

22. Transition to IFRS (continued)

Reconciliation of consolidated statement of comprehensive income for the year ended December 31, 2010:

(thousands of Canadian dollars)(unaudited)	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)	(1,733)	-	(95,608)
General and administrative expense	1c	(37,578)	(615)	-	(38,193)
Depreciation expense	1b, 7	(215,780)	86,695	4,493	(124,592)
Impairment loss	1d	-	(17,500)	-	(17,500)
Exploration and evaluation expense	2	-	(752)	-	(752)
Gains on derivatives		50,514	-	-	50,514
Other income	1a	-	46,142	-	46,142
Operating income before finance and taxes		**(21,991)**	**112,237**	**3,179**	**93,425**
Finance expense	3,4,7	(29,128)	(767)	**(4,493)**	(34,388)
Income (loss) before taxes		**(51,119)**	**111,470**	**(1,314)**	**59,037**
Income tax recovery (expense)	5,8	6,911	(26,342)	1,314	(18,117)
Net income (loss) and comprehensive income (loss)		**$ (44,208)**	**$ 85,128**	**$ -**	**$ 40,920**

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%.

22. 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 December 31, 2009 and March 31, 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.

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Paul G. Haggis(1)
John A. Howard (2)(3)
Andy J. Mah
Ronald A. McIntosh (1)(2)
Sheila H. O'Brien (2)(3)
Carol D. Pennycook (1)(3)
Steven Sharpe

(1) Member of Audit Committee
(2) Member of Reserve Evaluation Committee
(3) Member of Human Resources, Compensation & Corporate Governance Committee

Officers

Andy J. Mah, President and CEO
Kelly I. Drader, CFO
Patrick J. Cairns, Senior Vice President
Craig Blackwood, Vice President, Finance
Weldon M. Kary, Vice President, Geosciences and Land
Neil Bokenfohr, Vice President, Exploitation

Corporate Secretary

Jay P. Reid, Partner
Burnet, Duckworth and Palmer LLP

Auditors

PricewaterhouseCoopers LLP

Bankers

The Bank of Nova Scotia
National Bank of Canada
Bank of Montreal
Royal Bank of Canada
Canadian Imperial Bank of Commerce
Union Bank, Canada Branch
Alberta Treasury Branches
HSBC Bank Canada
BNP Paribas (Canada)

Independent Reserve Evaluators

Sproule Associates Limited

Legal Counsel

Burnet, Duckworth and Palmer LLP

Transfer Agent

Computershare Trust Company of Canada

Abbreviations

bbls	- barrels
bbls/d	- barrels per day
boe	- barrels of oil equivalent (6 mcf = 1 bbl)
boe/d	- barrels of oil equivalent per day
mcf	- thousand cubic feet
mcf/d	- thousand cubic feet per day
mmcf	- million cubic feet
mmcf/d	- million cubic feet per day
bcf	- billion cubic feet
tcf	- trillion cubic feet
gj	- gigajoules
NGLs	- natural gas liquids
WTI	- West Texas Intermediate

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Toronto Stock Exchange Trading Symbols

Shares: AAV
7.75% Convertible Debentures: AAV.DBD
8.00% Convertible Debentures: AAV.DBG
5.00% Convertible Debentures: AAV.DBH

New York Stock Exchange Trading Symbol

Shares: AAV