Management's discussion and analysis ("MD&A") of the financial condition and the results of operations should be read in conjunction with the December 31, 2011 audited consolidated financial statements, together with the accompanying notes.

Additional information about Yangarra filed with Canadian securities commissions is available on-line at www.sedar.com.

The MD&A has been prepared using information that is current to April 4, 2012.

The financial information presented herein has been prepared on the basis of International Financial Reporting Standards ("IFRS"). Throughout this discussion, percentage changes are calculated using numbers rounded to the decimal to which they appear. All references to dollar amounts are in Canadian dollars.

BOE Presentation – *Production information is commonly reported in units of barrel of oil equivalent ("boe"). For purposes of computing such units, natural gas is converted to equivalent barrels of oil using a conversion factor of six thousand cubic feet to one barrel of oil. This conversion ratio of 6:1 is based on an energy equivalent wellhead value for the individual products. Such disclosure of boe may be misleading, particularly if used in isolation. Readers should be aware that historical results are not necessarily indicative of future performance.*

Special Note Regarding Non-IFRS Measures *– This MD&A includes references to financial measures commonly used in the oil and gas industry. The terms "net petroleum and natural gas revenue" (petroleum and natural gas sales less royalties, production expenses and transportation costs) and "funds flow from operations" (net loss for the period adjusted for non-cash items in the statement of operations before changes in non-cash working capital) are not IFRS measures and do not have standardized meanings prescribed by IFRS.*

Forward-looking Statements – *Certain information regarding the Company set forth in this report, including management's assessment of the Company's future plans and operations, contain forward-looking statements that involve substantial known and unknown risks and uncertainties. These risks and uncertainties, many of which are beyond the Company's control, include the impact of general economic conditions and specific industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, the lack of available qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. The Company's actual results, performance or achievements could differ materially from those expressed in, or implied by, these forward-looking statements, and accordingly, no assurance can be given that any events anticipated by the forward-looking statements will transpire or occur, or if any of them do, what benefits the Company can derive from such events.*

Company Description and Outlook

Yangarra is a junior oil and gas company engaged in the exploration, development and production of natural gas and oil with operations in Western Canada, with a main focus on Central Alberta, where the Company has extensive infrastructure and land holdings.

Yangarra is dedicated to creating value for its shareholders through its commitment to a clear business strategy and performance objectives. The Company's strategy is to increase the value of its corporate assets through the drill bit and by assembling a large focused land base in Central Alberta that features high-quality, long-life light oil and liquids-rich gas reserves. The Company has assembled a significant future drilling inventory and will strive to grow this inventory through drilling, geology and strategic acquisitions.

During the year ended December 31, 2011 the Company completed the following significant milestones:

- Average daily production for 2011 was 1,205 boe/d a 137% increase from 2010. Fourth quarter 2011 production was 1,720 boe/d (49% oil and NGL's), which is a 37% increase from the third quarter 2011.
- Oil and gas sales during the year were $20.7 million a 217% increase from 2010 and cash flow from operations were $16.3 million ($0.15 per share - basic) a 452% increase from 2010. Fourth quarter 2011 oil and gas sales were $7.6 million with cash flow from operations of $5.7 million ($0.05 per share - basic) a 40% and 16% increase from the third quarter of 2011, respectively.
- Operating costs for 2011, including $0.79/boe of transportation costs, were $8.18/boe this represents a 27% decrease from 2010.
- Operating netback of $38.15 per boe, a 58% increase from the $24.12 per boe reported in 2010.
- Capital expenditures were $64 million for 2011 and $20 million in the fourth quarter of 2011.
- As at December 31, 2011, the Company had a working capital deficit of $34 million (excluding mark to market on commodity contracts and non-cash flow through share premium obligations) resulting in a debt to annualized trailing quarter cash flow ratio of 1.49 to 1. However due to a step change in the production levels in the month of December 2011, the annualized the December cash flow results in a debt to cash flow ratio of 0.97 to 1.

Operations Update:

- The Glauconite and Cardium plays are currently the primary focus of the development plan and combined with the Viking play represent over five years of currently identified drilling inventory.
- Production averaged 2,270 boe/d for the month of December. Two wells that were flowing at a combined rate of 600 boe/d net to Yangarra were shut-in by the operator for the months of December 2011 and January 2012 to allow for drilling on multi-well pads and for the installation of incremental compression.
- All dry gas production of approximately 1.2 mmcf/d (200 boe/d) was shut in early January 2012.
- The planned 2012 capital expenditures have been reduced from $50 million to $35 million. With the revised capital budget the Company will drill 16 gross (8.5 net) horizontal wells with an increased focus on wells with high oil and natural gas liquid ("NGL") volumes.

Summary Financial Information

	2011 Q4	2011 Q3	2010 Q4	Year ended 2011	Year ended 2010
Statement of Operations and Deficit					
Net income (loss) for the period (before tax)	$ (3,142,348)	$ 5,424,074	$ (1,037,921)	$ 4,872,697	$ (2,599,497)
Net income (loss) for the period	$ (2,155,583)	$ 4,106,091	$ (183,574)	$ 1,385,698	$ (1,745,150)
Net income (loss) per share - basic	$ (0.02)	$ 0.04	$ 0.00	$ 0.01	$ (0.03)
Net income (loss) per share - fully diluted	$ (0.02)	$ 0.03	$ 0.00	$ 0.01	$ (0.03)
Weighted average number of shares - basic	116,336,405	116,307,057	73,869,598	105,960,324	57,581,832
Weighted average number of shares - fully diluted	123,740,262	124,209,770	80,497,022	113,781,122	57,581,832
Statement of Cash Flows					
Funds flow from operations	$ 5,686,411	$ 4,967,853	$ 1,567,756	$ 16,341,180	$ 2,959,286
Funds flow from operations per share - basic	$ 0.05	$ 0.04	$ 0.02	$ 0.15	$ 0.05
Funds flow from operations per share - fully diluted	$ 0.05	$ 0.04	$ 0.02	$ 0.14	$ 0.05

	Year ended 2011	Year ended 2010
Balance Sheet		
Property and equipment	$ 119,374,220	$63,263,452
Total assets	$ 141,291,044	$68,373,813

Business Environment

	Year average 2011	Year average 2010
West Texas Intermediate ("WTI") (US$/bbl)	$ 95.05	$ 77.19
AECO gas (Cdn$/GJ)	$ 3.49	$ 4.08
Foreign Exchange (Cdn$/US$)	$ 1.01	$ 0.97

Crude oil prices strengthened during 2011, with the West Texas Intermediate (WTI) reference price averaging US$95.05 per barrel compared with US$77.19 per barrel in 2010. Demand for crude oil is generally tied to global economic growth, but is also influenced by factors such as political instability, market uncertainty, weather conditions and government regulations.

In 2011, the political instability in several Middle Eastern and North African countries contributed to the increase in crude oil prices. The uncertainty related to the debt crisis in the US and several European countries and the potential effect on global economic growth also contributed to the volatility in oil prices in 2011. The WTI forward strip price for 2012 is currently approximately US$109.

Oil prices in Canada are also affected by the Canada/U.S. dollar exchange rate since the WTI reference price of oil is in U.S. dollars. During 2011, the Canadian dollar strengthened slightly against the U.S. dollar, averaging US$1.01 to Cdn$1 compared with US$0.97 to Cdn$1 in 2010. The strengthening of the Canadian dollar partially offsets the increased WTI benchmark pricing experienced during 2011.

AECO natural gas prices for 2011 decreased to $3.49 per GJ from $4.08 per GJ in 2010. Demand from the price sensitive power and industrial sectors and warm weather patterns in the Northeast part of the United States temporarily offset the strong incremental production from shale gas plays. Strong US natural gas production is limiting the upside to natural gas price recovery.

Results of Operations

Net petroleum and natural gas production, pricing and revenue

	2011 Q4	2011 Q3	2010 Q4	Year ended 2011	Year ended 2010
Daily production volumes					
Natural gas (mcf/d)	4,740	4,161	2,564	3,874	2,151
Oil (bbl/d)	536	384	260	361	116
NGL's (bbl/d)	258	132	54	145	28
Royalty income (boe/d)	136	44	19	53	6
Combined (boe/d 6:1)	1,720	1,253	761	1,205	509
Product pricing (includes royalty income)					
Oil ($/bbl)	$93.54	$89.25	$ 80.54	$ 92.79	$ 74.70
NGL ($/bbl)	$55.18	$54.00	$ 62.20	$ 58.60	$ 56.04
Gas ($/mcf)	$3.55	$3.93	$ 3.93	$ 3.92	$ 3.92
Combined ($/boe)	$49.88	$47.85	$ 40.94	$ 48.55	$ 35.55
Revenue					
Petroleum & natural gas sales - Gross	$ 7,555,427	$ 5,378,932	$ 2,864,802	$ 20,742,259	$ 6,534,377
Royalty income	$ 335,618	$ 137,243	$ 93,882	$ 613,139	$ 123,106
Royalty expense	$ (563,262)	$ (209,529)	$ (128,984)	$ (972,706)	$ (165,309)
Petroleum & natural gas sales - Net	$ 7,327,783	$ 5,306,646	$ 2,829,700	$ 20,382,692	$ 6,492,174

Petroleum and natural gas sales increased by 217% in 2011 to $20.7 million from $6.5 million in 2010, the increase is attributable to:

- a 37% increase in average product prices; and
- a 137 % increase in production (on a boe basis).

The increased production in 2011 can be attributed to additional wells that were brought on production during 2011. The Company drilled or participated in 29 gross (15.5 net) horizontal wells during 2011.

The overall average price earned by the Company was higher when compared to 2010 due to increased oil and natural gas liquids production (44% compared to 28% in 2010). The price of WTI increased by 23% and the price of natural gas deceased by 14% from 2010 and as a result the increased revenue from the oil and NGL production stream more than offset the decrease in the natural gas prices.

Fourth Quarter

Petroleum and natural gas sales increased by 40% in the fourth quarter of 2011 to $7.6 million from $5.4 million in the third quarter, the increase is attributable to:

- a 4% increase in average product prices; and
- a 37% increase in production (on a boe basis).

The Company continued to increase production and the overall average price earned by the Company was higher when compared to the third quarter due to increased oil and natural gas liquids production (49% compared to 42% in the third quarter).

Royalty Income

	2011		2010	Year ended	
	Q4	Q3	Q4	2011	2010
Royalty Income	$ 335,618	$ 137,243	$ 93,882	$ 613,139	$ 123,106

Royalty income increased significantly in 2011 to $613,139. The majority of royalty income is a result of the 15% sliding scale royalty purchased in the Willesden Green area in March 2010. At the end of 2010 four wells had been drilled on the royalty lands and during 2011 an additional eight wells were added bringing to the total to 12 wells generating the 15% royalty income. Yangarra purchased the 15% overriding royalty from a 3rd party in 2010. As Yangarra owns a working interest in the royalty land a portion of the royalty is deemed inter-company and eliminated, however, if Yangarra had not purchased the royalty, total royalty paid to the 3rd party would have been approximately $1.5 million

Fourth Quarter

In the fourth quarter six wells were drilled on the royalty lands increasing the royalty income by $198,375 from the third quarter of 2011. In addition, as the majority of the new wells were not online at year-end royalty income is expected to increase further in the first quarter on 2012.

Royalty Expense

	2011		2010	Year ended	
	Q4	Q3	Q4	2011	2010
Royalty Expense	$ 563,262	$ 209,529	$ 128,984	$ 972,706	$ 165,309
Per boe	$3.56	$1.82	$ 1.84	$ 2.21	$ 0.90
As a % of sales	7%	4%	5%	5%	3%

Royalties increased to $972,706 for the year ended 2011 or 5% as a percentage of sales. The increase results from higher production during 2011 and two wells transitioning from the 5% horizontal well royalty framework to a full royalty burden.

Generally, royalty rates in Western Canada are sensitive to prevailing commodity prices and individual well production rates. The crown royalty rate on the new horizontal wells in Central Alberta is 5% for the earlier of 2 years or 60,000 boe of production.

Fourth Quarter

Royalties increased from $209,529 in the third quarter 2011 to $563,262 for Q4 2011, the increase results from a full quarter with the two wells that transitioned from the 5% horizontal well royalty framework to a full royalty burden.

Production and Transportation Costs

	2011 Q4	2011 Q3	2010 Q4	Year ended 2011	Year ended 2010
Production costs	$ 1,231,655	$ 742,035	$ 738,831	$ 3,248,011	$ 1,820,683
Per boe	$ 7.78	$ 6.44	$ 10.56	$ 7.38	$ 9.91
Transportation costs	$ 71,273	$ 116,075	$ 72,990	$ 348,431	$ 237,893
Per boe	$ 0.45	$ 1.01	$ 1.04	$ 0.79	$ 1.29

Production and transportation costs increased in 2011 to $3,596,442 on a dollar basis and decreased by 27% on a per boe basis when compared to 2011. The decrease is due to additional production volumes that have allowed the Company to achieve more economies of scale. This is due to improvements in the Company's operating practices and due to increased production in areas with facilities in place and where the majority of the costs are fixed.

Fourth Quarter

When compared to the third quarter of 2011, production costs on a per boe basis have increased by 11% due to delays in production coming on-line from fourth quarter drilling. Additional costs were incurred in anticipation of the new production and once the new wells are brought on-stream the Company expects production costs per boe to fall back in line with the yearly average.

Operating Netback

	2011 Q4	2011 Q3	2010 Q4	Year ended 2011	Year ended 2010
Revenues	$ 46.09	$46.31	$ 40.94	$ 47.16	$ 35.55
Royalty income	3.79	1.55	1.34	1.39	0.67
Royalty expense	(3.56)	(1.82)	(1.84)	(2.21)	(0.90)
Production costs	(7.78)	(6.44)	(10.56)	(7.38)	(9.91)
Transportation costs	(0.45)	(1.01)	(1.04)	(0.79)	(1.29)
Netback per boe	$ 38.08	$ 38.58	$ 28.84	$ 38.15	$ 24.12

Netbacks increased by 57% when compared to the year ended 2010. Netbacks were stronger due to higher oil and liquid sales and, therefore, higher prices for natural gas. The higher oil and liquid sales were a result of the Company's focus on Glauconite and Cardium wells in Willesden Green/Ferrier versus the gas-weighted Medicine Hat and Jaslan areas. The Company has also lowered operating costs as economies of scale are being realized in Central Alberta due to increasing volumes.

Fourth Quarter

The fourth quarter 2011 netback of $37.34 per boe is a 3% decrease from the $38.58 per boe reported in the third quarter of 2011. The decrease in netbacks from the third quarter of 2011 is due to decreased commodity prices and increased operating costs in the fourth quarter.

Depletion, depreciation and accretion

	2011 Q4	2011 Q3	2010 Q4	Year ended 2011	Year ended 2010
Depletion and depreciation	$ 3,279,485	$ 2,253,782	$ 1,562,204	$ 8,304,505	$ 3,811,668
Per boe	$ 20.73	$ 19.55	$ 22.31	$ 18.88	$ 20.52
Accretion	$ 23,416	$ 30,067	$ 33,583	$ 107,281	$ 126,628

Depletion and depreciation increased in 2011 compared to 2010 due to significant increases in capital expenditures and production in 2011. On a per boe basis, the reserve base increased from 2010, which has more than offset the increased production, resulting in a decreased DD&A rate per boe in 2011.

Fourth Quarter

The increase in DD&A on a boe basis from the third quarter of 2011 is due to the timing between the capital spent in the quarter and the production on-stream times.

General and Administrative expenses ("G&A")

	2011 Q4	2011 Q3	2010 Q4	Year ended 2011	Year ended 2010
Gross G&A expenses	$ 819,829	$ 539,781	$ 542,819	$ 2,552,677	$ 1,470,821
G&A recoveries	$ (431,140)	$ (294,355)	$ (161,988)	$ (1,178,506)	$ (309,246)
Net G&A expenses	$ 388,689	$ 245,426	$ 380,831	$ 1,374,170	$ 1,161,575
Per boe	$ 2.46	$ 2.13	$ 5.44	$ 3.12	$ 6.25

General and administrative expenses increased by 18% in 2011 due to additional staffing and office requirements to manage the increased production levels. G&A recoveries also increased in 2011 as a result of additional partners on the Yangarra operated wells. On a per boe basis G&A decreased by 50% due to increased efficiencies in head office operations.

Fourth Quarter

G&A costs in the fourth quarter increased form the third quarter due to increased consulting costs required to manage the additional activity during the quarter, however, on a per boe basis G&A costs increased by 16% when compared to the third quarter.

Other expenses

	2011 Q4	2011 Q3	2010 Q4	Year ended 2011	Year ended 2010
Interest and financing fees	$ (6,231)	$ 69,541	$ 94,780	$ 213,866	$ 265,251
Dividends on preferred shares	$ -	$ -	$ 12,603	$ 8,960	$ 50,000
Stock-based compensation	$ 258,300	$ 148,828	$ 961,984	$ 1,682,583	$ 1,746,939

Interest and financing fees for 2011 is for interest on the revolving operating demand loan for which the average amount drawn in 2011 was $15 million compared to $6 million in 2010.

The increase in stock-based compensation is a result of options granted to new employees.

Dividends on preferred shares are at a rate of 5% payable semi-annually in cash or common shares of the Company on $1,000,000 of preferred shares issued in December 2009 in conjunction with the settlement of the subordinated credit facility. The preferred shares were redeemed in March 2011 resulting in the reduced dividend paid for the first half of 2011.

Fourth Quarter

The average amount drawn on the revolving operating demand loan in the fourth quarter of 2011 was $17 million, however, the increased interest was offset by an adjustment by the bank for an over payment of interest in the second and third quarter.

Income Taxes

	2011		2010	Year ended	
	Q4	Q3	Q4	2011	2010
Deferred Income Tax (recovery) expense	$ (986,765)	$ 1,317,983	$ (854,347)	$ 3,486,999	$ (854,347)

The Company's effective tax rate for 2011 was approximately 26.5%, however, Yangarra did not pay income taxes in 2011 and does not expect to pay income taxes in 2012 as is has sufficient tax pools to cover.

The Company has the following estimated tax pools as at December 31:

		Year ended	
	Rate %	2011	2010
Canadian exploration expenses	100	$ 7,995,628	$ 8,408,719
Canadian development expenses	30	54,255,805	20,573,717
Canadian oil and gas property expenses	10	10,282,395	7,642,652
Undepreciated capital costs	10-30	21,672,917	16,507,709
Non-capital losses (various expiry dates)	100	375,794	1,434,634
Share issuance costs	5 Years	2,686,066	1,547,617
		$ 97,268,605	$56,115,048

Commodity price risk contracts

	2011		2010	Year ended	
	Q4	Q3	Q4	2011	2010
Commodity contract settlement	$ 161,775	$ 834,284	$ (32,766)	$ 1,269,687	$ 40,734
Change in fair value of commodity contracts	$ (5,385,319)	2,888,898	(6,270)	(1,491,875)	113,361
	$ (5,223,544)	$ 3,723,182	$ (39,036)	$ (222,188)	$ 154,095

As at December 31, 2011, the Company was committed to the following commodity price risk contracts for the sale of oil:

2012 Hedges:

- 100 barrels per day from January 1 to December 31, 2012 at a fixed price of $99.00 CAD per barrel;
- 200 barrels per day from January 1 to December 31, 2012 at a fixed price of $97.00 CAD per barrel;
- 200 barrels per day from January 1 to December 31, 2012 at a fixed price of $90.00 CAD per barrel;
- 100 barrels per day from January 1 to December 31, 2012 at a fixed price of $93.25 CAD per barrel; and
- 100 barrels per day from January 1 to December 31, 2012 at a fixed price of $100.00 CAD per barrel.

2013 Hedges:

- 200 barrels per day from January 1 to December 31, 2013 at a fixed price of $98.00 CAD per barrel; and
- 100 barrels per day from January 1 to December 31, 2013 at a fixed price of $97.50 CAD per barrel.

In addition, the Company entered into collars which provided a floor and a ceiling for the price it received for oil as follows:

- 100 barrels per day from January 1 to December 31, 2012 at a floor price of $95.00 CAD per barrel and a ceiling price of $110.00 CAD per barrel; and
- 100 barrels per day from January 1 to December 31, 2012 at a floor price of $95.00 CAD per barrel and a ceiling price of $109.15 CAD per barrel.

As at December 31, 2011, the Company was committed to the following commodity price risk contracts on the AECO basis:

- 2,000 mmbtu/day of AECO Basis for Nov11-Mar12 at a price ranging from -$0.38 to -$0.42 USD/mmbtu.

The mark-to market on the hedges was in a loss position of $1,491,875 as at December 31, 2011. During the year ended December, 2011 $1,269,687 (2010 – $40,734) worth of contracts were settled.

Liquidity and Capital Resources

During the year ended 2011, the Company generated $16,341,180 of funds flow from operations compared to $2,959,286 in the 2010 comparative period. Funds flow from operations was higher for the 2011 period due primarily to the increase in petroleum and natural gas revenue.

As at December 31, 2011, the $26,245,533 (2010 – $5,559,208) reported amount of bank debt was comprised of $24,450,000 (2010 – $4,600,000) drawn on the revolving operating demand loan and $1,795,533 (2010 – $959,208) of bank overdraft. The Company is subject to a financial covenant with respect to working capital, which the Company was in compliance with at December 31, 2011. The facility is secured by a fixed and floating charge on the assets of the Company and is secured by a general security agreement.

As at December 31, 2011, the maximum amount available under the revolving operating demand loan was $40,000,000 (December 31, 2010 – $12,000,000) at an interest rate of bank prime plus 1.0% per annum, payable monthly.

The Company is compliant with all debt covenants as at December 31, 2011.

As at December 31, 2011, the Company had a working capital deficit of $34 million (excluding mark to market on commodity contracts and non-cash flow through share premium obligations) compared to a deficit of $12 million at December 31, 2010.

Annualizing the three month cash flow ending December 31, 2011 and using the December 31, 2011 working capital amount (excluding commodity contract liability and the flow through liability) the Company has a debt to cash flow ratio of 1.49 to 1. However, due to a step change in the production levels in the month of December 2011, the annualized December cash flow results in a debt to cash flow ratio of 0.97 to 1.

Capital Spending

Capital spending is summarized as follows:

	2011 Q4	2011 Q3	2010 Q4	Year ended 2011	Year ended 2010
Land and lease rentals	$ 740,630	$ 953,884	$ 3,827,343	$ 3,782,231	$ 5,449,298
Drilling and completion	15,727,731	14,892,270	10,593,594	49,808,464	16,777,716
Geological and geophysical	162,825	359,277	190,640	947,870	505,583
Equipment	3,104,371	2,799,884	2,148,426	9,487,625	4,272,875
	$ 19,735,557	$19,005,315	$16,760,003	$ 64,026,190	$27,005,472

The Company drilled or participated in 29 gross (15.5 net) horizontal wells during 2011 and purchased 92 sections of land. The drilling resulted in significant increases in production, proved the Rock Creek play and allowed the Company to drill industries first horizontal well in the Second White Specks reservoir.

The average drill and complete cost per well was $3.2 million mainly as a result of drilling deeper wells with more complicated fracture programs. As a result of reduced costs and improved drilling and fracturing efficiencies the Company is forecasting a per well drill and complete cost of $2.6 million in 2012.

The planned 2012 capital expenditures have been reduced from $50 million to $35 million. With the revised capital budget the Company will drill 16 gross (8.5 net) horizontal wells with an increased focus on wells with high oil and natural gas liquid ("NGL") volumes. The Company will operate the 2012 drilling program with one drilling rig instead of two drilling rigs as previously planned.

Decommissioning Liabilities

As at December 31, 2011, the undiscounted fair value of the decommissioning liability associated with the Company's existing properties was estimated to be $6,120,528 for which $4,898,222 has been recorded using a discount rate of 1.51% - 3.35%, an inflation rate of 2% and an estimated weighted average timing of cash flows of 8.7 years.

Off Balance Sheet Arrangements

There were no off balance sheet arrangements, other than the office commitments and truck lease commitments which are accounted for as an operating lease.

Related Party Transactions

During the year ended December 31, 2011 and 2010, the Company was charged or invoiced the following amounts by certain of its officers and directors and by companies controlled by certain of the Company's officers and directors:

	2011 Q4	2011 Q3	2010 Q4	Year ended 2011	Year ended 2010
Administration and consulting fees	$ 60,000	$ 51,284	$ 35,055	$ 237,694	$ 168,270
Production and capital expenditures	104,451	113,886	87,698	339,896	614,056
	$ 164,451	$ 165,170	$ 122,753	$ 577,590	$ 782,326

Included in accounts payable and accrued liabilities at December 31, 2011 is $117,020 (December 31, 2010 – $29,668) relating to the above transactions. These transactions were in the normal course of operations and were measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

During the year ended December 31, 2011 the Company entered into a trust agreement with an officer of the Company for an asset in Central Alberta used a field office. The Company holds the asset in trust while the officer retains legal title.

Share Capital

Details of changes in the number of outstanding equity instruments are detailed in the following table:

	Common Shares	Preferred Shares	Warrants	Stock Options
Balance - December 31, 2010	**79,718,127**	**1,000,000**	**9,452,000**	**7,808,800**
Transfer agent correction	(70)	-	-	-
Financing March 2011	23,632,500	-	-	-
Financing June 2011	12,500,000	-	-	-
Grant of options	-	-	-	4,175,000
Exercise of options	260,000	-	-	(260,000)
Expiry of options	-	-	-	(115,000)
Cancelation of options	-	-	-	(255,000)
Exercise of warrants	496,500	-	(496,500)	-
Redemption of preferred shares	-	(1,000,000)	-	-
Balance - December 31, 2011	**116,607,057**	**-**	**8,955,500**	**11,353,800**
Grant of options				1,045,000
Expiry of options				(790,000)
Exercise of warrants	5,104,666	-	(5,104,666)	-
Expiry of warrants		-	(2,430,834)	-
Balance - Date of MD&A	**121,711,723**	**-**	**1,420,000**	**11,608,800**

Contingency

In December 2009, the Company terminated the Standstill Agreement that it had with an industry partner regarding a joint producing property and served that industry partner with a Statement of Claim issued from The Court of Queen's Bench of Alberta, by which the Company claims breach of the agreements between the parties, gross negligence and default of operator. The Company seeks judgment for specified and such further damages to be determined by the Court, as well as appointment as operator. The Company significantly increased the statement of claim based on the information provided by the defendant and expects the matter to go to trial during 2012. The potential outcome of the lawsuit and claims are undetermined, however, they may be material. As the likely outcome of this litigation cannot be determined at this time, no provision has been made in the consolidated financial statements.

Commitments

As at December 31, 2010, the Company had until December 31, 2011 to incur $9,690,000 of qualifying flow-through expenditures related to flow-through shares issued in March, May, June and October 2010 of which all required expenditures have been incurred. The Company has until December 31, 2012 to incur $10,000,000 of qualifying flow-through expenditures related to flow-through shares issued in June 2011. As at December 31, 2011 the company has approximately $6 million remaining to spend on the 2012 flow thorough commitment.

The Company has entered into lease agreements for office premises, field equipment and Company vehicles with estimated minimum annual payments as follows:

2012	$	185,571
2013	$	109,695

Financial instruments and financial risk management

The Company's financial instruments include cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, bank debt, credit facility and preferred shares. The carrying values of accounts receivable, accounts payable and accrued liabilities, bank debt, credit facility and preferred shares approximate their fair values due to their relatively short periods to maturity.

The Company is required to classify fair value measurements using a hierarchy that reflects the significance of the inputs used in making the measurements. The fair value hierarchy is as follows:

- Level 1 - quoted prices in active markets for identical assets or liabilities;
- Level 2 - inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly; and
- Level 3 - inputs for the asset or liability that are not based on observable market data.

The fair value of cash and bank debt is level 1 it is determined using amounts held at/lent by financial institutions. The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Company's activities. The Company has exposure to credit risk, liquidity risk and market risk as a result of its use of financial instruments. This note presents information about the Company's exposure to each of the above risks and the Company's objectives, policies and processes for measuring and managing these risks. Further quantitative disclosures are included throughout these financial statements. The Board of Directors has overall responsibility for the establishment and oversight of the Company's risk management framework. The Board has implemented and monitors compliance with the risk management policies as set out herein:

a. Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations. A substantial portion of the Company's accounts receivable are with natural gas and liquids marketers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks. Purchasers of the Company's natural gas and liquids are subject to credit review to minimize the risk of non-payment. As at December 31, 2011, the maximum credit exposure is the carrying amount of the accounts receivable and accruals of $16,109,194 (December 31, 2010 – $3,752,477). As at December 31, 2011, the Company's receivables consisted of $14,007,979 from joint venture partners and other trade receivables and $2,101,216 of revenue receivable from petroleum and natural gas marketers.

Receivables from petroleum and natural gas marketers are typically collected on the 25th day of the month following production. The Company's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large purchasers. The Company historically has not experienced any significant collection issues with its petroleum and natural gas marketers. All of the revenue accruals and receivables from petroleum and natural gas marketers were received in January and February 2012.

Joint venture receivables are typically collected within one to three months of the joint venture bill being issued to the partner. The Company mitigates the risk from joint venture receivables by obtaining partner approval of capital expenditures prior to starting a project. However, the receivables are from participants in the petroleum and natural gas sector, and collection is dependent on typical industry factors such as commodity price fluctuations, escalating costs and the risk of unsuccessful drilling. Further risk exists with joint venture partners as disagreements occasionally arise which increases the potential for non-collection. For properties that are operated by the Company, production can be withheld from joint venture partners who are in default of amounts owing. In addition, the Company often has offsetting amounts payable to joint venture partners from which it can net receivable balances.

The Company did not provide for any doubtful accounts nor was it required to write-off any receivables during the three months ended December 31, 2011. The Company would only choose to write-off a receivable balance (as opposed to providing an allowance) after all reasonable avenues of collection had been exhausted.

As at December 31, 2011, the Company considers its receivables to be aged as follows:

Not past due	$	7,133,913
Past due by less than 90 days		5,398,582
Past due by more than 90 days		3,576,699
	$	16,109,194

b. Liquidity risk

Liquidity risk is the risk that the Company will incur difficulties meeting its financial obligations as they are due. The Company's approach to managing liquidity is to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions without incurring unacceptable losses or risking harm to the Company's reputation.

The Company prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. The Company uses authorizations for expenditures on both operated and non-operated projects to further manage capital expenditures.

To facilitate the capital expenditure program, the Company has a credit facility agreement which is regularly reviewed by the lender. The Company monitors its total debt position monthly. The Company also attempts to match its payment cycle with collection of petroleum and natural gas revenues on the 25th of each month. The Company anticipates it will have adequate liquidity to fund its financial liabilities through its future cash flows. The Company's financial liabilities are comprised of accounts payable and accrued liabilities, bank debt and the credit facility, which have expected maturities of less than one year resulting in their current classification on the balance sheet.

c. Market risk

Market risk consists of interest rate risk, currency risk and commodity price risk. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing returns. The Company may use both financial derivatives and physical delivery sales contracts to manage market risks. All such transactions are conducted in accordance with a risk management policy as set out herein:

i. 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 Company is exposed to interest rate fluctuations on its bank debt which bears interest at a floating rate. For the year ended December 31, 2011, if interest rates had been 1% lower with all other variables held constant, earnings for the year would have been $260,000 (2010 - $62,000) higher, due to lower interest expense. An equal and opposite impact would have occurred had interest rates been higher by the same amount. The Company had no interest rate swap or financial contracts in place at December 31, 2011.

ii. Currency risk
Foreign currency exchange rate risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in foreign exchange rates. All of the Company's petroleum and natural gas sales are denominated in Canadian dollars, however, the underlying market prices in Canada for petroleum and natural gas are impacted by changes in the exchange rate between the Canadian and United States dollar. The Company had no outstanding forward exchange rate contracts in place at December 31, 2011.

iii. Commodity price risk
Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for petroleum and natural gas are impacted by world economic events that dictate the levels of supply and demand as well as the relationship between the Canadian and United States dollar, as outlined above.

Capital disclosures

The Company's objective when managing capital is to maintain a flexible capital structure which will allow it to execute its capital expenditure program, which includes expenditures in oil and gas activities which may or may not be successful. Therefore, the Company monitors the level of risk incurred in its capital expenditures to balance the proportion of debt and equity in its capital structure.

The Company considers its capital structure to include shareholders equity:

	December 31, 2011	*December 31, 2010*
Shareholders' equity	$ 76,627,244	$ 47,835,896

The Company monitors capital based on annual funds from operations and capital expenditure budgets, which are updated as necessary and are reviewed and periodically approved by the Board of Directors.

The Company manages its capital structure and makes adjustments by continually monitoring its business conditions including the current economic conditions, the risk characteristics of the Company's petroleum and natural gas assets, the depth of its investment opportunities, current and forecasted net debt levels, current and forecasted commodity prices and other facts that influence commodity prices and funds from operations such as quality and basis differentials, royalties, operating costs and transportation costs.

In order to maintain or adjust the capital structure, the Company considers its forecasted funds from operations while attempting to finance an acceptable capital expenditure program including acquisition opportunities, the current level of bank credit available from the Company's lender, the level of bank credit that may be attainable from its lender as a result of petroleum and natural gas reserve growth, the availability of other sources of debt with different characteristics than existing debt, the sale of assets, limiting the size of the capital expenditure program and the issue of new equity if available on favorable terms. At December 31 2011, the Company's capital structure was not subject to external restrictions.

Selected Historical Financial Information

	2011 Q4($)	2011 Q3($)	2011 Q2($)	2011 Q1($)
Petroleum and natural gas sales	**7,555,427**	5,378,932	4,283,356	3,524,544
Net petroleum and natural gas revenue	**7,327,783**	5,306,646	3,468,715	2,844,144
Net income (loss)	**(2,155,583)**	4,106,091	1,665,821	(2,230,631)
Net income (loss) per share – basic	**(0.02)**	0.04	0.02	(0.03)
Net income (loss) per share – diluted	**(0.02)**	0.03	0.01	(0.02)
Funds flow from operations	**5,686,411**	4,967,853	3,151,665	2,535,251
Funds flow from operations per share – basic	**0.05**	0.04	0.03	0.03
Funds flow from operations per share – fully diluted	**0.05**	0.04	0.03	0.03
Net capital expenditures	**19,735,557**	19,005,315	7,160,655	18,124,663

	2010 Q4($)	2010 Q3($)	2010 Q2($)	2010 Q1($)
Petroleum and natural gas sales	2,864,802	1,821,333	839,054	1,009,188
Net petroleum and natural gas revenue	2,017,879	1,299,935	439,729	646,831
Net loss	(183,574)	(228,916)	(1,185,541)	(147,119)
Net loss per share – basic	(0.00)	(0.00)	(0.02)	(0.00)
Net loss per share – diluted	(0.00)	(0.00)	(0.02)	(0.00)
Funds flow from operations	1,567,756	921,972	59,390	410,168
Funds flow from operations per share – basic	0.02	0.02	0.00	0.01
Funds flow from operations per share – fully diluted	0.02	0.02	0.00	0.01
Net capital expenditures	16,760,003	2,689,049	3,756,574	3,799,846

Business Risks and Uncertainties

The Company is exposed to several operational risks inherent in exploring, developing, producing and marketing crude oil and natural gas. These inherent risks include: economic risk of finding and producing reserves at a reasonable cost; financial risk of marketing reserves at an acceptable price given current market conditions; cost of capital risk associated with securing the needed capital to carry out the Company's operations; risk of environment impact; and credit risk of non-payment for sales contracts and joint venture partners.

The Company attempts to control operating risks by maintaining a disciplined approach to implementation of its exploration and development programs. Exploration risks are managed by hiring experienced technical professionals and by concentrating the exploration activity on specific core regions that have multi-zone potential where the Company has experience and expertise. The Company also generates internal prospects and participates in projects where ownership interest is considered sufficient to minimize risk. Operational control allows the Company to manage costs, timing and sales of production and to ensure new production is brought on-stream in a timely manner.

The Company maintains a comprehensive insurance program to reduce risk to an acceptable level and to protect it against significant losses.

Environmental Risks

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Compliance with such legislation can require significant expenditures and a breach could result in the imposition of fines and penalties, some of which could be material. Senior management continually assesses new and existing regulatory requirements and environmental risks and determines the impact these risks might have on the Company, as well as the appropriate actions necessary to manage those risks. These assessments and the resulting policy decisions are discussed quarterly with the Board of Directors which evaluates the performance and effectiveness of the Company's environmental policies and programs.

The Company's environmental responsibilities includes removing property, plant and equipment as well as reclaiming land and property to its original state, subsequent to the completion of oil and natural gas extraction activities. This requirement results in an asset retirement obligation that provides current recognition of estimated expenditures that will be incurred in the future. The Company's decommissioning liabilities are discussed in further detail under "Critical Accounting Estimates" below, as well as in note 6 to the Company's Condensed Interim Consolidated Financial Statements.

Disclosure Controls and Procedures

The Company's certifying officers will file a Venture Issuer Basic Certificate with respect to the information contained in its financial statements and respective accompanying Management's Discussion and Analysis. The Venture Issuer Basic Certification includes a 'Notice to Reader' stating that the certifying officers do not make any representations relating to the establishment and maintenance of disclosure controls and procedures and internal control over financial reporting, as defined in National Instrument 52-109 – Certification of Disclosure in Issuers' Annual and Interim Filings.

Critical Accounting Estimates

The preparation of the financial statements in accordance with IFRS requires management to make judgments, estimates and assumptions that affect reported amounts and presentation of assets, liabilities, revenues, expenses and disclosures of contingencies and commitments. Such estimates primarily relate to unsettled transactions and events at the statement of financial position date which are based on information available to management at each financial statement date. Actual results could differ from those estimated.

Judgments, estimates and assumptions are continuously evaluated and are based on management's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances.

Property and equipment

The Company capitalizes costs in connection with the development of its oil and gas projects. The measurement of these costs at each financial statement date requires estimates to be made with respect to equipment and drilling activities. The estimate of the percentage of completion of various projects at the financial statement date affects P&E additions and the related accrued liability. An increase in the measurement amount of these items would increase P&E and accrued liabilities accordingly.

Reserves

Reserves and resources are used in the unit of production calculation for depletion and depreciation as well as impairment analysis. The quantity of reserves is subject to a number of estimates and projections including assessment of engineering data, projected future rates of production, commodity prices, regulatory changes, foreign exchange rates, operating costs and sustaining capital expenditures. These estimates and projections are uncertain as the Company does not have a long commercial production history to assist in the development of these forward-looking estimates. However, all reserve and associated financial information is evaluated and reported on by a firm of qualified independent reserve evaluators in accordance with the standards prescribed by applicable securities regulators.

The calculation of future cash flows based on these reserves is dependent on a number of estimates including: production volumes, facility performance, commodity prices, royalties, operating costs, sustaining capital, foreign exchange and tax rates. The price used in our assessment of future cash flows is based on the Company's independent evaluator's estimate of future prices and evaluated for reasonability by the Company against other available information. The Company believes these prices are reasonable estimates for a long-term outlook.

Impairment

The Company assesses its P&E and E&E assets for possible impairment if there are events or changes in circumstances that indicate the carrying values of the assets may not be recoverable. Such indicators include changes in the Company's business plans, changes in commodity prices, evidence of physical damage and significant downward revisions to estimated recoverable volumes or increases in estimated future development expenditures.

The assessment for impairment for P&E and E&E assets involves comparing the carrying value of the CGU with the higher of value in use calculations and fair value less costs to sell. Determination as to whether and how much an asset is impaired involves management estimates on highly uncertain matters such as future commodity prices, the effects of inflation on operating expenses, discount rates, production profiles and the outlook for regional supply-and-demand conditions for crude oil, natural gas and liquids. Impairment is recognized in earnings in the period in which carrying amount exceeded the recoverable amount. The Company has not recognized any impairment as at December 31, 2011.

Depletion and depreciation

Depletion of resource assets is measured over the life of proved and probable reserves on a unit-of-production basis and commences when the wells are substantially complete and after commercial production has begun. Reserve estimates and the associated future capital can have a significant impact on earnings, as these are key components to the calculation of depletion. A downward revision in the reserve estimate or an upward revision to future capital would result in increased depletion, reduced earnings and reduced carrying value of petroleum and natural gas property assets.

Decommissioning liabilities

The Company measures decommissioning liabilities at each financial statement date. The estimate is based on the Company's share of costs to reclaim the resource assets and certain facilities related to the projects as well as other resource assets associated with future expansions. To determine the future value of the liability, estimates of the amount, timing and inflation of the associated abandonment costs are made. The present value of the cost is recorded as the decommissioning liability using a risk-free discount rate. Due to the long-term nature of current and future project developments, abandonment costs will be incurred many years in the future. As a result of these factors, different estimates could be used for such abandonment costs and the associated timing. Assumptions of higher future abandonment costs, regulatory changes, higher inflation, lower risk-free rates or an assumption of earlier or specified timing of abandonment would cause the decommissioning liability of the corresponding asset to increase. These changes would also cause future accretion expenses to increase and future earnings to decrease.

Deferred taxes

Deferred income tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amount and the tax basis of assets and liabilities. An estimate is required for both the timing and corresponding tax rate for this reversal. Should these estimates change, it may impact the measurement of the Company's assets or liabilities as well as deferred tax recovery or expense recognized to earnings. Where unfavorable evidence exists, additional considerations and evidence for recognition of deferred tax assets is required. The Company has applied management's judgment and evaluated applicable factors necessary in making this determination and has concluded that the positive evidence in consideration of the estimated future cash flows based on reserve reports from the Company's independent engineers, does not sufficiently outweigh negative factors. The Company only recognizes deferred tax assets arising from unused tax losses to the extent that the Company has sufficient taxable temporary differences or it is probable that sufficient taxable profit will be available against which the unused tax losses can be utilized. The Company has not recognized a deferred tax asset.

Contingencies

By their nature, contingencies will only be resolved when one or more of the 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.

Other areas of estimates

The recognition of amounts in relation to stock-based compensation requires estimates related to valuation of stock options at the time of issuance. The fair value of foreign exchange contracts is calculated using valuation models that require estimates as to future market prices. By their nature, these estimates are subject to measurement uncertainty and the effect of changes in such estimates on the financial statements for current and future periods could be significant.

International Financial Reporting Standards ("IFRS")

Effective January 1, 2011, International Financial Reporting Standards ("IFRS") have replaced Canadian GAAP for publicly accountable enterprises. The Company has adopted IFRS for the interim and annual periods beginning on January 1, 2011, including comparative information pertaining to 2010.

Information regarding the Company's accounting policies and transition to IFRS can be found in notes 1, 2 and 18 to the Condensed Interim Consolidated Financial Statements. Significant items to note upon transition include:

Depletion and depreciation

Under IFRS, depletion of P&E properties is calculated at a unit-of-account level using proved and probable reserves as the basis, as opposed to using only proved reserves as was required practice under Canadian GAAP. This has resulted in significantly lower depletion under IFRS than under Canadian GAAP.

Decommissioning liabilities

Under IFRS, the assumptions used in calculating asset retirement obligations are to be analyzed at each balance sheet date and updated to reflect current market conditions when appropriate. Due to the change recorded on January 1, 2010, resulting from the use of the risk-free rate as opposed to the credit-adjusted risk-free rate, the amount of accretion recorded under IFRS is lower than that recorded under Canadian GAAP. In addition, the Company has chosen to show accretion separately on its financial statements as opposed to including with depletion and depreciation, as was common practice under Canadian GAAP.

Transition adjustments

At January 1, 2010, the assumptions used to calculate the decommissioning liabilities were altered to reflect current market conditions, as required under IFRS. The change resulted in an increase to the liability of $755,065.

Flow-through Shares

Flow-through shares are a Canadian tax incentive which is the subject of specific guidance under Canadian GAAP, however there is no specific guidance under IFRS. Under Canadian GAAP, when flow-through shares are issued they are recorded at face value. The related future tax liability is established for the tax effect of the difference between the tax basis and the book basis of the assets when renounced and is recorded as a reduction of share capital. There is no income statement effect associated with the issuance of these shares.

The Company has adopted a policy under IFRS where the proceeds from the offering are to be allocated between the sale of the shares and the sale of the tax benefit. The allocation is made based on the difference between the quoted market price of the existing shares and the amount an investor pays for the flow-through shares. A liability is established for this difference that is reversed upon renunciation of the tax benefit. The difference between this liability and the deferred tax liability is recorded as an income tax expense. This has resulted in a re-classification between deficit and share capital at January 1, 2010 of $4,047,525.