Management's discussion and analysis ("MD&A") of the financial condition and the results of operations should be read in conjunction with the June 30, 2012 unaudited consolidated financial statements and the December 31, 2011 audited consolidated financial statements of Yangarra Resources Ltd ("Yangarra" or "the Company"), 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 August 17, 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 contains the terms "funds from (used in) operations" and "funds from (used in) operations per share", which should not be considered an alternative to or more meaningful than cash flow from (used in) operating activities as determined in accordance with IFRS. These terms do not have any standardized meaning as prescribed by IFRS. Yangarra's determination of funds from (used in) operations and funds from (used in) operations per share may not be comparable to that reported by other companies. Management uses funds from (used in) operations to analyze operating performance and leverage, and considers funds from (used in) operations to be a key measure as it demonstrates the Company's ability to generate cash necessary to fund future capital investments and to repay debt, if applicable. Funds from (used in) operations is calculated using cash flow from (used in) operating activities as presented in the statement of cash flows before changes in non-cash working capital. Yangarra presents funds from (used in) operations per share whereby per share amounts are calculated using weighted average shares outstanding consistent with the calculation of earnings per share.*

The following table reconciles funds from (used in) operations to cash flow from (used in) operating activities, which is the most directly comparable measure calculated in accordance with IFRS:

	2012		2011	6 Months ended	
	Q2	Q1	Q2	2012	2011
Cash flow from (used in) operating activities	$ 5,012,962	$ 1,937,376	$ 2,142,787	$ 6,950,338	$ 3,799,260
Changes in non-cash working capital	(1,519,959)	3,209,178	1,008,878	1,689,219	1,887,656
Funds from (used in) operations	$ 3,493,003	$ 5,146,554	$ 3,151,665	$ 8,639,557	$ 5,686,916

The Company considers corporate netbacks to be a key measure as they demonstrate Yangarra's profitability relative to current commodity prices. Corporate netbacks are comprised of operating, funds flow and net loss netbacks. Operating netback is calculated as the average sales price of its commodities and then subtracts royalties, operating costs and transportation expenses. Funds flow netback starts with the operating netback and further deducts general and administrative costs, finance expense and adds finance income as well as realized gains on financial instruments. To calculate the net income (loss) netback, Yangarra takes the funds flow netback and deducts share-based compensation expense as well as depletion and depreciation charges, accretion expense, unrealized gains on financial instruments, any *impairment or exploration and evaluation expense and deferred income taxes. There is no IFRS measure that is reasonably comparable to netbacks.*

Net debt and working capital (deficit), which represent current assets less current liabilities, excluding current derivative financial instruments, are used to assess efficiency, liquidity and the general financial strength of the Company. There is no IFRS measure that is reasonably comparable to net debt or working capital (deficit).

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 quarter ended June 30, 2012 the Company completed the following significant milestones:

- Net income before taxes of $6.5 million ($0.05/share), including $8.2 million of hedging gains.
- Production was 2,022 boe/d which is a 107% increase from the second quarter 2011 and the Company estimates that 800 boe/d (not including the 200 boe/d of shut-in dry gas) was behind pipe or shut-in on average for the quarter.
- Oil and NGL production was 38% of total production in the second quarter compared with 38% in the second quarter of 2011 and 42% in the first quarter of 2012. The decrease in liquids production from the first quarter, 2012 was a result of lower than expected declines in several gas-weighted Glauconite wells and down time related to a turnaround at a third party deep cut plant.
- Oil and gas sales including royalty income was $5.9 million with cash flow from operations of $3.5 million ($0.03 per share basic) a 32% and 10% increase from the comparable period in 2011, respectively.
- Operating costs for the second quarter, including $0.85/boe of transportation costs, were $7.99/boe which represents an 11% decrease from the comparable period in 2011.
- The field netback was $23.81 per boe ($22.59 not including $1.22 per boe of realized hedging gains) a 42% decrease from the comparable period in 2011. Realized prices were negatively impacted by higher WTI/Edmonton par differentials, lower natural gas prices and lower liquids pricing.
- Capital expenditures of $3.0 million focused on completing carry over costs from wells spud during the first quarter and various infrastructure projects.
- As at June 30, 2012, the Company had a working capital deficit of $33 million (excluding mark to market on commodity contracts) compared to $34 million at December 31, 2011.
    - The Company has utilized 80% of its $42 million credit facility.
    - Due to significant decreases in natural gas prices and widening of the Edmonton par to WTI differential the company has managed capital expenditures to minimize the reliance on debt and will continue to employee this strategy until commodity prices improve.

Operations Update

Due to wet field conditions, the Company limited capital expenditures during the quarter. Drilling operations will resume when conditions improve. As previously reported (see press release dated May 24, 2012), the Company has significant shut-in volumes in four new wells that are tied into facilities which are expected to increase the liquids ratio back to 45-50% of total production. The installation of incremental compression has been delayed by landowner objections and Yangarra has elected to wait until those issues are dealt with rather than expend more capital to produce the wells with alternate options. One of the four new wells was placed on-stream in mid August as capacity in the existing compressor became available.

Current production is approximately 1,900 boe/d and third quarter production is expected to be 1,700 – 2,000 boe/d. The Company will execute a capital plan for the remainder of the 2012 that is focused on oil targets and funded with cash flow and senior bank debt.

Summary Financial Information

	2012 Q2	2012 Q1	2011 Q2	6 Months ended 2012	6 Months ended 2011
Statements of Comprehensive Income (Loss)					
Net income (loss) for the period (before tax)	$ 6,451,923	$ (983,334)	$ 3,473,637	$ 5,468,589	$ 2,590,971
Net income (loss) for the period	$ 3,305,628	$ (1,790,789)	$ 1,665,821	$ 1,514,839	$ (564,810)
Net income (loss) per share - basic	$ 0.03	$ (0.02)	$ 0.02	$ 0.01	$ (0.01)
Net income (loss) per share - fully diluted	$ 0.03	$ (0.02)	$ 0.01	$ 0.01	$ (0.01)
Statements of Cash Flow					
Funds flow from (used in) operating activities	$ 3,493,003	$ 5,146,554	$ 3,151,665	$ 8,639,557	$ 5,686,916
Funds flow from (used in) operating activities per share - basic	$ 0.03	$ 0.04	$ 0.03	$ 0.07	$ 0.06
Funds flow from (used in) operating activities per share - fully diluted	$ 0.03	$ 0.04	$ 0.03	$ 0.07	$ 0.05
Statements of Financial Position					
Property and equipment	$ 121,329,749	$ 122,891,333	$ 86,947,461	$ 122,891,333	$ 86,947,461
Total assets	$ 142,907,001	$ 147,718,686	$ 94,455,249	$ 147,718,686	$ 94,455,249
Working Capital (deficit), excluding MTM on commodity contracts and flow-through share obligation	$ (33,456,912)	$ (33,920,294)	$ (5,463,023)	$ (33,456,912)	$ (5,463,023)
Shareholders equity	$ 81,125,416	$ 77,613,288	$ 73,665,560	$ 81,125,416	$ 73,665,560
Weighted average number of shares - basic	121,711,152	117,494,735	104,762,826	119,602,943	95,427,181
Weighted average number of shares - fully diluted	121,711,152	118,962,415	113,332,471	119,602,943	103,996,826

Business Environment

	2012 Q2	2012 Q1	2011 Q2	6 Months ended 2012	6 Months ended 2011
West Texas Intermediate ("WTI") (US$/bbl)	$ 93.34	$ 102.94	$ 102.56	$ 98.15	$ 98.33
AECO gas (Cdn$/GJ)	$ 1.74	$ 2.03	$ 3.88	$ 2.06	$ 3.81

Crude oil prices weakened in the second quarter of 2012, with the West Texas Intermediate ("WTI") reference price averaging US$93.35 per barrel compared to US$102.94 per barrel in the first quarter of 2012 and $102.56 in the same period in 2011 and a further reduction to realized prices due to Edmonton par to WTI differential of over $12/bbl. The average realized price of Yangarra's crude oil was $81.97/bbl for the second quarter of 2012 compared to $100.30/bbl a year ago, while NGLs averaged $55.22/bbl versus $64.69/bbl in 2011.

During the three months ended June 30, 2012, benchmark natural gas prices in Canada fell 55% from the same period last year and 14% from the first quarter of 2012. AECO prices averaged $1.74/GJ throughout the second quarter of 2012 compared to $3.88/GJ a year ago. Yangarra's average realized gas price during the three-month period was $2.05/mcf versus $3.99/mcf last year.

Results of Operations

Net petroleum and natural gas production, pricing and revenue

	2012 Q2	2012 Q1	2011 Q2	6 Months ended 2012	6 Months ended 2011
Daily production volumes					
Natural gas (mcf/d)	6,115	6,018	3,594	6,066	3,288
Oil (bbl/d)	269	438	265	354	262
NGL's (bbl/d)	397	347	103	372	94
Royalty income					
Natural gas (mcf/d)	1,432	1,481	26	1,456	43
Oil (bbl/d)	3	12	3	8	6
NGL's (bbl/d)	94	91	1	93	2
Combined (boe/d 6:1)	2,022	2,139	975	2,080	919
Product pricing (includes royalty income)					
Oil ($/bbl)	$ 81.97	$ 90.95	$ 100.30	$ 87.56	$ 93.49
NGL ($/bbl)	55.22	64.96	64.69	59.81	63.57
Gas ($/mcf)	2.05	2.09	3.99	2.07	3.88
Combined ($/boe)	$ 32.13	$ 39.80	$ 48.71	$ 36.07	$ 47.77
Revenue					
Petroleum & natural gas sales - Gross	$ 5,265,664	$ 6,907,412	$ 4,283,356	$ 12,173,076	$ 7,807,900
Royalty income	645,002	839,177	35,848	1,484,179	140,278
Total sales	5,910,666	7,746,589	4,319,204	13,657,255	7,948,178
Royalty expense	(283,131)	(446,817)	(56,547)	(729,948)	(199,915)
Petroleum & natural gas sales - Net	$ 5,627,535	$ 7,299,772	$ 4,262,657	$ 12,927,307	$ 7,748,263

Total revenue increased by 37% in Q2 2012 to $5.9 million from $4.3 million in the same period 2011, the increase is attributable to:

- a 34% decrease in average product prices and;
- a 107 % increase in production (on a boe basis).

Compared to the first quarter 2012, total revenue decreased by 24%, the decrease is attributable to:

- a 19% decrease in average product prices and;
- a 5% decrease in production (on a boe basis).

The decreased production in the second quarter of 2012 can be attributed to natural declines, limited drilling during spring break-up and significant volumes remaining behind pipe due to facility constraints and a third party plant turn around during the quarter.

The overall average price earned by the Company was lower when compared to the same period in 2011 and the first quarter of 2012 due to significant decreases in the natural gas price. The price received for oil decreased from the first quarter 2012 as well, as decreases in WTI prices and increases in the Edmonton Par to WTI differential.

Oil and NGL production was 38% of total production in the second quarter compared with 38% in the second quarter of 2011 and 42% in the first quarter of 2012. The decrease in liquids production was a result of lower than expected declines in several gas-weighted Glauconite wells and down time related to a turnaround at a third party deep cut plant.

During the quarter, the Company experienced significant delays related to landowner objections to adding increased compression in a third party facility to which four new tested wells are tied into and to which new two additional shut in wells are going to be tied into. Rather than expend additional capital to accelerate the process the Company has chosen to be patient and let declines create room in the existing facility. One well has come on-stream as room became available in the existing compressor and the operator advises that the landowner objection is working its way through the regulatory process.

Royalty Income

	2012 Q2	2012 Q1	2011 Q2	6 Months ended 2012	6 Months ended 2011
Royalty Income	$ 645,002	$ 839,177	$ 35,848	$ 1,484,179	$ 140,278

Royalty income increased in second quarter of 2012 to $645,002 from $35,848 in the comparable period in 2011. 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. The decrease in royalty income in the second quarter of 2012 is due to lower commodity prices.

Royalty Expense

	2012 Q2	2012 Q1	2011 Q2	6 Months ended 2012	6 Months ended 2011
Royalty Expense	$ 283,131	$ 446,817	$ 56,547	$ 729,948	$ 199,915
Per boe	$ 1.55	$ 2.30	$ 0.64	$ 1.93	$ 1.20
As a % of sales	5%	6%	1%	5%	3%

Royalties decreased to $283,131 in the second quarter 2012 from $446,817 for the first quarter of 2012 and $56,547 in the comparable period in 2011. The decrease in the second quarter results from the additional production from new wells being brought on-stream that are covered by the 5% royalty program and lower commodity prices.

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.

Production and Transportation Costs

	2012 Q2	2012 Q1	2011 Q2	6 Months ended 2012	6 Months ended 2011
Production costs	$ 1,314,640	$ 952,673	$ 702,480	$ 2,267,313	$ 1,274,321
Per boe	$ 7.14	$ 4.89	$ 7.92	$ 5.99	$ 7.66
Transportation costs	$ 156,536	$ 147,372	$ 91,462	$ 303,908	$ 161,083
Per boe	$ 0.85	$ 0.76	$ 1.03	$ 0.80	$ 0.97

Production and transportation costs increased in the second quarter of 2012 to $1,471,176 and decreased by 11% on a per boe basis when compared to the comparable period in 2011.

The increase in operating costs from the previous quarter and the comparable period in 2011 is due to maintenance work and various field projects completed during the quarter as the company took the opportunity to complete this work with limited drilling operations.

Depletion, depreciation and accretion

	2012 Q2	2012 Q1	2011 Q2	6 Months ended 2012	6 Months ended 2011
Depletion and depreciation	$ 4,880,246	$ 4,056,492	$ 1,507,794	$ 8,936,738	$ 2,771,238
Per boe	$ 26.53	$ 20.84	$ 17.00	$ 23.61	$ 16.66
Accretion	$ 25,343	$ 23,188	$ 21,211	$ 48,531	$ 53,798

Depletion and depreciation increased in the second quarter 2012 compared to the first quarter of 2012 due to an impairment of $936,126 relating to the Jaslan and Medicine Hat areas. These areas were natural gas weighted and lower realized natural gas prices resulted in the impairment.

General and administrative expenses ("G&A")

	2012 Q2	2012 Q1	2011 Q2	6 Months ended 2012	6 Months ended 2011
Gross G&A expenses	$ 604,584	$ 600,021	$ 705,454	$ 1,244,993	$ 1,193,066
G&A recoveries	(45,063)	(229,690)	(240,690)	(315,003)	(453,011)
Net G&A expenses	$ 559,521	$ 370,331	$ 464,764	$ 929,852	$ 740,055
Per boe	$ 3.04	$ 1.90	$ 5.24	$ 2.46	$ 4.45

Gross G&A costs in the second quarter remained relatively constant when compared to the first quarter of 2012 and on a per boe basis G&A costs increased by 60% due to lower recoveries than the previous quarter. On a net basis G&A was higher than the comparable period in 2011 due to lower recoveries.

Other expenses

	2012 Q2	2012 Q1	2011 Q2	6 Months ended 2012	6 Months ended 2011
Interest and financing fees	$ 327,675	$ 257,061	$ 96,290	$ 584,736	$ 150,556
Dividends on preferred shares	$ -	$ -	$ -	$ -	$ 8,960
Stock-based compensation	$ 125,124	$ 231,000	$ -	$ 356,124	$ 1,275,455

Interest and financing fees for the three months ended June 30, 2012 is for interest on the revolving operating demand loan for which the average amount drawn in 2012 was $29,050,000.

During the three months ended June 30, 2012, the Company granted a total of 935,000 stock options which vested immediately. The total fair value of the options was estimated at $431,000 of which $99,835 was capitalized.

Deferred Taxes

	2012 Q2	2012 Q1	2011 Q2	6 Months ended 2012	6 Months ended 2011
Deferred Income Tax (recovery) expense	$ 3,146,295	$ 807,455	$ 1,807,816	$ 3,953,750	$ 3,155,781

During the six months ended June 30, 2012, the Company recorded a deferred income tax expense of $3,146,295 compared to an expense of $1,807,816 in the same period last year. For 2012, this expense is a function of the overall net loss adjusted for tax related to the eligible capital expenditures being spent in relation to the June 2011 flow-through share issuance. As these eligible costs are incurred, the Company reverses the flow-through share premium liability and recognizes the deferred income tax expense at that time.

Yangarra does not have current income taxes payable and does not expect to pay current income taxes in 2012 as the Company had estimated tax pools of $86 million available at June 30, 2012.

Commodity price risk contracts

	2012 Q2	2012 Q1	2011 Q2	6 Months ended 2012	6 Months ended 2011
Commodity contract settlement	$ 223,840	$ (425,781)	$ 244,004	$ (201,941)	$ 273,628
Change in fair value of commodity contracts	7,989,633	(1,819,208)	1,850,977	6,170,425	1,004,546
	$ 8,213,473	$ (2,244,989)	$ 2,094,981	$ 5,968,484	$ 1,278,174

As at June 30, 2012, the Company was committed to the following commodity price risk contracts for the sale of oil:

2012 Hedges:

- 100 bbl/d from January 1 to December 31, 2012 at a fixed price of $99.00 CAD/bbl;
- 200 bbl/d from January 1 to December 31, 2012 at a fixed price of $97.00 CAD/bbl;
- 100 bbl/d from January 1 to December 31, 2012 at a fixed price of $93.25 CAD/bbl; and
- 100 bbl/d from January 1 to December 31, 2012 at a fixed price of $100.00 CAD/bbl.

2013 Hedges:

- 200 bbl/d from January 1 to December 31, 2013 at a fixed price of $98.00 CAD/bbl;
- 100 bbl/d from January 1 to December 31, 2013 at a fixed price of $97.50 CAD/bbl;
- 200 bbl/d from January 1 to December 31, 2013 at a fixed price of $98.30 USD/bbl;
- 100 bbl/d from January 1 to December 31, 2013 at a fixed price of $98.00 USD/bbl;
- 100 bbl/d from January 1 to December 31, 2013 at a fixed price of $104.80 CAD/bbl and;
- Sold calls on 200 bbl/d d from January 1 to December 31, 2013 at $110 US/bbl.

2014 Hedges:

- 100 bbl/d from January 1 to December 31, 2014 at a fixed price of $98.30 CAD/bbl;
- 100 bbl/d from January 1 to December 31, 2014 at a fixed price of $100.00 CAD/bbl; and
- 100 bbl/d from January 1 to December 31, 2014 at a fixed price of $101.05 CAD/bbl.

As at June 30, 2012, the Company was committed to the following commodity price risk contracts on the AECO basis:

- 1,000 GJ/d at $5.25/ for April 2012 – October 2012; and
- 1,000 GJ/d at $2.22/GJ for July 2012 – October 2012.

The mark-to market on the hedges was in a gain position of $4,678,550 as at June 30, 2012 (December 31, 2011 – a loss position of $1,491,875).

Company Netbacks ($/boe)

	2012 Q2	2012 Q1	2011 Q2	6 Months ended 2012	6 Months ended 2011
Sales Price	$ 28.62	$ 35.49	$ 48.31	$ 32.15	$ 46.93
Royalty income	3.51	4.31	0.40	3.92	0.84
Royalty expense	($1.55)	(2.30)	(0.64)	(1.93)	(1.20)
Production costs	(7.14)	(4.89)	(7.92)	(5.99)	(7.66)
Transportation costs	(0.85)	(0.76)	(1.03)	(0.80)	(0.97)
Operating netback	**22.59**	**31.85**	39.12	27.35	37.94
G&A and other (excludes non-cash items)	(3.04)	(1.90)	(5.24)	(2.46)	(4.45)
Realized gain (loss) on financial instruments	1.22	(2.19)	2.75	(0.53)	1.64
Finance expenses	(1.78)	(1.32)	(1.09)	(1.54)	(0.96)
Cash flow netback	**18.99**	**26.44**	35.54	**22.82**	**34.18**
Depletion and depreciation	(26.53)	(20.84)	(17.00)	(23.61)	(16.66)
Accretion	(0.14)	(0.12)	(0.24)	(0.13)	(0.32)
Stock-based compensation	(0.68)	(1.19)	-	(0.94)	(7.66)
Unrealized gain (loss) on financial instruments	43.43	(9.35)	20.88	16.30	6.04
Deferred income tax	(17.10)	(4.15)	(20.39)	(10.44)	(18.97)
Net Income (loss) netback	**$ 17.97**	**$ (9.20)**	$ 18.79	**$ 4.00**	**$ (3.39)**

The second quarter 2012 operating netback of $22.59 per boe is a 29% decrease from the $31.85 per boe reported in the first quarter of 2012. The decrease in operating netbacks from the first quarter of 2012 is due to primarily a reduction in commodity prices.

Liquidity and Capital Resources

The following table summarizes the change in working capital during the three months ended June 30, 2012, March 31, 2012 and the year ended December 31, 2011:

	Three Months Ended June 30, 2012	Three Months Ended March 31, 2012	Year Ended December 31, 2011
Working capital (deficit) - beginning of period (1)	$ (33,920,294)	$ (34,028,162)	$ (11,472,461)
Cash flow from (used in) operating activities	3,493,003	5,146,554	16,341,180
Capital expenditures	(3,007,918)	(7,584,519)	(64,608,688)
Issuance of shares	6,500	2,545,833	25,711,807
Working capital (deficit) - end of period (1)	$ (33,428,709)	$ (33,920,294)	$ (34,028,162)
Credit facility limit	$ 42,000,000	$ 42,000,000	$ 40,000,000

(1) Excludes non-cash change in fair value of commodity contracts

As at June 30, 2012, the Company had a working capital deficit of $33 million (excluding mark to market on commodity contracts) lower than the working capital deficit of $34 million at March 31, 2012.

Yangarra's strategy is to maintain a debt to cash flow ratio of 1.0:1 however, due to significant decreases in natural gas prices and widening of the Edmonton par to WTI differential, Yangarra's debt to trailing year cash flow ratio as at June 30, 2012 was 1.7:1. The Company's goal is to return to the target ratio as commodity prices improve and will manage capital expenditures accordingly.

During the three months ended June 30, 2012, the Company generated $3.5 million of cash flow from operations compared to $5.1 million in the first quarter of 2012. Cash flow from operations was lower for the second quarter when compared to the first quarter of 2012 due to natural declines and the limited drilling during spring break-up combined with lower commodity prices and significant shut-in volumes. The increase from the same period in 2011 is due to increased production volumes.

As at June 30, 2012, the $38,611,081 (2011 – $26,245,533) reported amount of bank debt was comprised of $33,650,000 (2011 – $24,450,000) drawn on the revolving operating demand loan and $4,961,069 (2011 – $1,795,533) of bank overdraft. The Company is subject to a financial covenant with respect to working capital, which the Company was in compliance with at June 30, 2012. 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 June 30, 2012, the maximum amount available under the revolving operating demand loan was $42,000,000 (December 31, 2011 – $40,000,000) at an interest rate of bank prime plus 1.5% per annum, payable monthly. The Company is compliant with all debt covenants as at June 30, 2012.

Capital Spending

Capital spending is summarized as follows:

	2012 Q2	2012 Q1	2011 Q2	6 Months ended 2012	6 Months ended 2011
Land and lease rentals	$ (15,366)	$ 147,489	$ 748,282	$ 132,123	$ 2,087,717
Drilling and completion	2,383,800	6,621,898	4,901,729	9,005,698	19,188,463
Geological and geophysical	327,646	154,180	255,136	481,826	425,768
Equipment	309,944	651,953	1,255,508	961,897	3,583,370
	$ 3,006,024	$ 7,575,520	$ 7,160,655	$ 10,581,544	$25,285,318

Capital expenditures of $3.0 million were focused Central Alberta with capital spent on completing wells and infrastructure projects.

Decommissioning Liabilities

As at June 30, 2012, the undiscounted fair value of the asset retirement obligation associated with the Company's existing properties was estimated to be $6,266,813 for which $5,146,748 has been recorded using a discount rate of 1.46% - 1.74%, an inflation rate of 2% and an estimated weighted average timing of cash flows of 8.5 years.

Off Balance Sheet Arrangements

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

Related Party Transactions

During the three and six months ended June 30, 2012 and 2011, 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:

	2012 Q2	2012 Q1	2011 Q2	6 Months ended 2012	6 Months ended 2011
Administration and consulting fees	$ 47,457	$ 47,048	$ 46,912	$ 94,505	$ 190,775
Production and capital expenditures	16,375	35,966	103,684	52,341	95,285
	$ 63,832	$ 83,014	$ 150,596	$ 146,846	$ 286,060

Included in accounts payable and accrued liabilities at June 30, 2012 is $nil (December 31, 2011 – $117,020) 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.

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, 2011	**116,607,057**	**-**	**8,955,500**	**11,353,800**
Grant of options	-	-	-	1,385,000
Forfeiture of options	-	-	-	(2,000,800)
Expiry of options	-	-	-	(168,000)
Exercise of warrants	5,104,666	-	(5,104,666)	-
Expiry of warrants	-	-	(2,430,834)	-
Balance - June 30, 2012	**121,711,723**	**-**	**1,420,000**	**10,570,000**
Forfeiture of options	-	-	-	(330,000)
Balance - Date of MD&A	**121,711,723**	**-**	**1,420,000**	**10,240,000**

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 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

The Company had until December 31, 2012 to incur $10,000,000 of qualifying flow-through expenditures related to flow-through shares issued in June 2011. The flow-through commitment was fully spent in 2011and during first quarter of 2012.

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

2012	$	119,719
2013	$	160,095
2014	$	50,400

Financial Instruments and Financial Risk Management

The Company's financial instruments include accounts receivable, accounts payable and accrued liabilities, bank debt, other long term debt, commodity contracts and preferred shares. The carrying values of accounts receivable, accounts payable and accrued liabilities and bank debt 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 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 June 30, 2012, the maximum credit exposure is the carrying amount of the accounts receivable and accruals of $9,495,792 (2011 – $16,109,194). As at June 30, 2012, the Company's receivables consisted of $8,276,512 from joint venture partners and other trade receivables and $1,219,280 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. To mitigate the risk associated with of dealing with a smaller marketer the Company has entered into an arrangement with Computershare to allow them to retain ownership of the product. All of the revenue accruals and receivables from petroleum and natural gas marketers were received in July and August 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 and six months ended June 30, 2012. 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.

b. As at June 30, 2012, the Company considers its receivables to be aged as follows:

Not past due	$ 4,448,982
Past due by less than 90 days	1,139,489
Past due by more than 90 days	3,907,321
	$ 9,495,792

c. 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, as disclosed in note 5, 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 statement of financial position.

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 three months ended June 30, 2012, if interest rates had been 1% lower with all other variables held constant, earnings for the period would have been $76,555 (2011 - $23,585) 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 June 30, 2012.

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 June 30, 2012.

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.

Selected Historical Financial Information

	2012 Q2($)	2012 Q1($)	2011 Q4($)	2011 Q3($)
Petroleum and natural gas sales	**5,265,664**	6,907,412	7,555,427	5,378,932
Net petroleum and natural gas revenue	**5,627,535**	7,299,772	7,327,783	5,306,646
Net income (loss)	**3,305,628**	(1,790,789)	(2,155,583)	4,106,091
Net income (loss) per share – basic	**0.03**	(0.02)	(0.02)	0.04
Net income (loss) per share – diluted	**0.03**	(0.02)	(0.02)	0.03
Funds flow from operations	**3,493,003**	5,146,554	5,686,411	4,967,853
Funds flow from operations per share – basic	**0.03**	0.04	0.05	0.04
Funds flow from operations per share – fully diluted	**0.03**	0.04	0.05	0.04
Net capital expenditures	**3,006,024**	7,575,520	19,735,557	19,005,315

	2011 Q2($)	2011 Q1($)	2010 Q4($)	2010 Q3($)
Petroleum and natural gas sales	4,283,356	3,524,544	2,864,802	1,821,333
Net petroleum and natural gas revenue	4,262,657	2,844,144	2,017,879	1,299,935
Net loss	1,665,821	(2,230,631)	(183,574)	(228,916)
Net loss per share – basic	0.02	(0.03)	(0.00)	(0.00)
Net loss per share – diluted	0.01	(0.02)	(0.00)	(0.00)
Funds flow from operations	3,151,665	2,535,251	1,567,756	921,972
Funds flow from operations per share – basic	0.03	0.03	0.02	0.02
Funds flow from operations per share – fully diluted	0.03	0.03	0.02	0.02
Net capital expenditures	7,160,655	18,124,663	16,760,003	2,689,049

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 June 30, 2012.

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.