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, 2012 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 March 27, 2013.

The financial information presented herein has been prepared on the basis of International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. 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 flow from (used in) operations" and "funds flow from (used in) operations per share", which should not be considered an alternative to or more meaningful than cash 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 flow from (used in) operations and funds flow from (used in) operations per share may not be comparable to that reported by other companies. Management uses funds flow from (used in) operations to analyze operating performance and leverage, and considers funds flow 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 flow from (used in) operations is calculated using cash from (used in) operating activities as presented in the statement of cash flows before changes in non-cash working capital. Yangarra presents funds flow 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 flow from (used in) operations to cash from (used in) operating activities, which is the most directly comparable measure calculated in accordance with IFRS:

	2012	2011
Cash from operating activities	$ 17,016,431	$ 6,664,849
Changes in non-cash working capital	(2,428,026)	9,676,331
Funds flow from operations	$ 14,588,405	$ 16,341,180

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.*

Overview

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.

2012 Significant Events

During the year ended December 31, 2012 the Company completed the following significant milestones:

- Average daily production was 1,914 boe/d a 59% increase from 2011.
- Oil and gas sales for the year were $21 million a 6% increase from 2011, with cash flow from operations of $15 million ($0.12 per share - basic).
- Operating costs, including $0.84/boe of transportation costs, were $7.65/boe.
- Operating netback of $25.48 per boe, was a 38% decrease from the $41.05 per boe reported in 2011.
- Net Capital expenditures were $20 million for 2012.
- As at December 31, 2012, the Company had a bank debt and working capital deficit of $36 million ($33 million including mark to market on commodity contracts) compared to $34 million at December 31, 2011.

Operations Update

Since resuming the drilling program in September 2012, the Company has drilled 9 gross (6.2 net) oil wells. Yangarra has changed the drilling program with the adoption of mono-bore drilling and increased use of multi-well pads, effectively cutting drilling times by 50%.

The Company expects to complete construction of the new compressor facility at Ferrier in the second quarter of 2013. All Yangarra operated wells in the Ferrier area, including five standing wells, will be tied into the new facility flowing into Keyera's deep cut Strachan plant.

The $25 million 2013 capital budget will focus on development of Yangarra's Cardium light oil play with a four year inventory identified. The capital spending is expected to increase the Company's annual production by 25% to 2,400 boe/d with cash from operations estimated at $24 million ($0.20/share) and a 2013 debt to cash flow ratio of 1.5. The budget assumes an average price of US$85/bbl of WTI crude oil and an average price of $3.00/mcf of AECO natural gas.

Annual Financial Information

	2012	2011	2010
Statements of Comprehensive Income (Loss)			
Petroleum & natural gas sales - Gross	$ 21,327,157	$ 20,742,259	$ 6,534,377
Net income (loss) for the year (before tax)	$ 21,174	$ 4,872,697	$ (2,599,497)
Net income (loss) for the year	$ (217,712)	$ 1,385,698	$ (1,745,150)
Net income (loss) per share - basic and diluted	$ (0.00)	$ 0.01	$ (0.03)
Statements of Cash Flow			
Funds flow from (used in) operating activities	$ 14,588,405	$ 16,341,180	$ 2,959,286
Funds flow from (used in) operating activities per share - basic and diluted	$ 0.12	$ 0.15	$ 0.05
Cash from (used in) operating activities	$ 17,016,431	$ 6,664,849	$ 95,378
Statements of Financial Position			
Property and equipment	$ 121,842,378	$ 119,374,219	$ 63,263,452
Total assets	$ 138,894,114	$ 141,291,043	$ 68,373,813
Working Capital (deficit), excluding MTM on commodity contracts and flow-through share obligation	$ (36,301,842)	$ (34,028,162)	$ (11,472,461)
Non-Current Financial Liabilities	$ (12,274,710)	$ (9,752,766)	$ (3,501,805)
Shareholders equity	$ (79,689,765)	$ (76,627,244)	$ (47,835,896)
Weighted average number of shares - basic	120,663,095	105,960,324	57,581,832
Weighted average number of shares diluted	120,663,095	113,781,122	57,581,832

Business Environment

	2012	2011
West Texas Intermediate ("WTI") (US$/bbl)	$ 94.21	$ 95.11
Edmonton (C$/bbl)	$ 87.02	$ 95.03
AECO gas (Cdn$/GJ)	$ 2.18	$ 3.49
U.S./Canadian Dollar Exchange	1.000	1.012

Crude oil prices remained relatively flat during 2012, with the West Texas Intermediate ("WTI") reference price averaging US$94.21/bbl compared with US$95.11 per barrel in 2011. Demand for crude oil is generally tied to global economic growth, but is also influenced by factors such as infrastructure, political instability, market uncertainty, weather conditions and government regulations.

Edmonton par differentials to WTI increased significantly during 2012 moving from a $0.08/bbl differential in 2011 to $7.19/bbl in 2012. The closest reference price point for Yangarra's oil is Edmonton par and therefore the widening differential has had a significant impact on the Company realized pricing.

AECO natural gas prices for 2012 decreased by 38% to $2.18 per GJ from $3.49 per GJ in 2011. The strong incremental production from shale gas plays in the US has suppressed the upside to natural gas price recovery.

Results of Operations

Net petroleum and natural gas production, pricing and revenue

	2012	2011
Daily production volumes		
Natural gas (mcf/d)	5,586	3,874
Oil (bbl/d)	350	361
NGL's (bbl/d)	341	145
Royalty income		
Natural gas (mcf/d)	1,273	202
Oil (bbl/d)	3	5
NGL's (bbl/d)	77	14
Combined (boe/d 6:1)	1,914	1,205
Product pricing (includes royalty income & realized gains/losses on commodity contracts)		
Oil ($/bbl)	$ 84.09	$ 92.79
NGL ($/bbl)	46.78	58.60
Gas ($/mcf)	2.49	3.92
Combined ($/boe)	$ 34.63	$ 48.55
Revenue		
Petroleum & natural gas sales - Gross	$ 21,327,157	$ 20,742,259
Royalty income	2,024,819	613,139
Commodity contract settlement	907,863	1,269,687
Total sales	24,259,839	22,625,085
Royalty expense	(1,057,597)	(972,706)
Petroleum & natural gas sales - Net	$ 23,202,242	$ 21,652,379
Change in fair value of contracts	$ 3,889,986	$ (1,491,875)
Total Revenue	$ 27,092,228	$ 20,160,504

Total sales increased by 7% in 2012 to $24.3 million from $22.6 million in 2011, the increase is attributable to:

- a 29% decrease in average product prices; and
- a 59 % increase in production (on a boe basis).

The increased production in 2012 can be attributed to additional wells that were brought on production during 2012. The Company drilled or participated in 8 gross (5.0 net) horizontal wells during 2012.

The overall average price earned by the Company was lower when compared to 2011 due lower natural gas reference pricing and lower liquids prices caused by a widening in the Edmonton par differential to WTI and a lower proportion of higher value condensate included in the total NGL product mix.

As a means of managing commodity price volatility and its impact on cash flows, Yangarra enters into various financial commodity agreements. Unsettled derivative financial contracts are measured at the date of the financial statements based on the fair value of the contracts. Changes in fair value result from volatility in forward curves of commodity prices and changes in the balance of unsettled contracts between periods. The changes in fair value are recognized in revenue as unrealized commodity contract gains and losses. Realized commodity contract gains and losses are recognized in revenue when derivative financial contracts are settled.

At December 31, 2012, Yangarra has contracted 700 bbl/day of expected 2013 oil production using WTI fixed price contracts at an average price of $98.99 per bbl and 300 bbl/day of expected 2014 oil production using WTI fixed price contracts at an average price of $99.78 per bbl. In addition, Yangarra has contracted approximately 3,500 GJ/day of expected 2013 natural gas production using AECO fixed price contracts at an average price of $3.46 per GJ. The Company's commodity risk program helps sustain Cash Flow during periods of lower prices. For additional information, see the Financial Instruments and Financial Risks Management section of this MD&A.

Royalty Income

	2012	2011
Royalty Income	$ 2,024,819	$ 613,139

Royalty income increased in 2012 to $2,024,819. 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 2012, there a total of 12 wells generating the 15% royalty income.

Royalty Expense

	2012	2011
Royalty Expense	$ 1,057,597	$ 972,706
Per boe	$ 1.51	$ 2.21
As a % of sales	5%	5%

Royalties increased to $1,057,597 for the year ended 2012 or 5% as a percentage of sales. The increase results from higher production during 2012 and older 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, individual well depth and 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. Deep natural gas wells have a royalty rate of 5% for the first 5 years of production.

Production and Transportation Costs

	2012	2011
Production costs	$ 4,771,074	$ 3,248,011
Per boe	$ 6.81	$ 7.38
Transportation costs	$ 585,176	$ 348,431
Per boe	$ 0.84	$ 0.79
Combined ($/boe)	$ 7.65	$ 8.17

Production and transportation costs increased in 2012 to $4,771,074 on a dollar basis and decreased by 6% on a per boe basis when compared to 2011. As production volumes have increased the Company has implemented improvements to operating practices by hiring more experienced personal and streamlining operations across the Central Alberta area. Fixed costs have remained flat as the Company is realizing the benefits of the field office that was put in place in 2011 and more efficient use of the Company operated crew trucks.

Depletion, depreciation and impairment and accretion

	2012	2011
Depletion and depreciation	$ 14,477,976	$ 8,304,505
Per boe	$ 20.67	$ 18.88
Impairment	$ 4,035,426	$ -
Accretion	$ 92,611	$ 107,281

Depletion, depreciation and impairment increased in 2012 compared to 2011 due to increased production in 2012 and the $ 4,035,426 impairment relating to the Jaslan and Medicine Hat cash generating units. On a per boe basis, the DD&A rate per boe increased in 2012 as the reserve base increased at a slower pace than the 2012 capital additions.

General and administrative expenses ("G&A")

	2012	2011
Gross G&A expenses	$ 2,484,072	$ 2,552,677
G&A recoveries	(717,536)	(1,178,506)
Net G&A expenses	$ 1,766,536	$ 1,374,171
Per boe	$ 2.52	$ 3.12

On a net basis, general and administrative expenses increased by 29% in 2012 due lower overhead recoveries as the Company had less partner wells. Yangarra established the majority of the corporate team during 2011 and has seen production growth without any major changes to the number of people; therefore, on a per boe basis, G&A decreased by 26%.

Other expenses

	2012	2011
Interest and financing fees	$ 1,491,050	$ 213,866
Dividends on preferred shares	$ -	$ 8,960
Stock-based compensation	$ 499,724	$ 1,682,583

Interest and financing fees for 2012 is for interest on the revolving operating demand loan for which the average amount drawn in 2012 was $36 million compared to $15 million in 2011.

During the year ended December 31, 2012, the Company granted a total of 3,155,000 stock options which vested immediately. The total fair value of the options was estimated at $727,900 of which $228,176 was capitalized.

Deferred Taxes

	2012	2011
Deferred income tax expense	$ 238,886	$ 3,486,999

The Company's effective tax rate for 2012 was 25%, however, Yangarra did not pay income taxes in 2012 and does not expect to pay income taxes in 2012 as is has sufficient tax pools to cover taxable income.

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

	2012	2011
Canadian exploration expenses	$ 12,488,867	$ 7,995,628
Canadian development expenses	52,019,745	54,255,805
Canadian oil and gas property expenses	10,392,075	10,282,395
Undepreciated capital costs	18,897,904	21,672,917
Non-capital losses (various expiry dates)	1,388,618	375,794
Share issuance costs	1,907,526	2,686,066
	$ 97,094,735	$ 97,268,605

Commodity price risk contracts

	Year Ended December 31, 2012	2011
Realized gain on contract settlement	$ 907,863	$ 1,269,687
Change in fair value of commodity contracts	3,889,986	(1,491,875)
	$ 4,797,849	$ (222,188)

As at December 31, 2012, the Company was committed to the following commodity price risk contracts for the sale of oil:

<u>2013 Contracts:</u>

- 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 USD/bbl.

2014 Contracts:

- 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;
- 100 bbl/d from January 1 to December 31, 2014 at a fixed price of $101.05 CAD/bbl; and
- Sold Swaption on 200 bbl/d @ $100.00 WTI/USD for January – December 2014.

As at December 31, 2012, the Company was committed to the following commodity price risk contracts on the AECO basis:

- 2,000 GJ/d at $3.51/GJ for January – December 2013;
- 1,000 GJ/d at $3.35/GJ for January – December 2013; and
- 500 GJ/d at $3.42/GJ for January – December 2013.

The fair value on the contracts was in a gain position of $2,398,111 as at December 31, 2012 (2011 – a loss position of $1,491,875).

The following table summarizes the sensitivity of the fair value of the Company's commodity price contracts as at December 31, 2012 to fluctuations in commodity prices, with all other variables held constant. When assessing the potential impact of these commodity price changes, the Company believes 10 percent volatility is a reasonable measure. Fluctuations in commodity prices potentially could have resulted in unrealized gains (losses) impacting income before tax as follows:

Sensitivities	Impact on Income Before Tax	
	Increase 10%	Decrease 10%
Crude oil	**(3,439,213)**	3,439,213
Natural Gas	**(383,250)**	383,250

Company Netbacks ($/boe)

	2012	2011
Sales Price	$ 31.74	$ 50.03
Royalty income	2.89	1.39
Royalty expense	(1.51)	(2.21)
Production costs	(6.81)	(7.38)
Transportation costs	(0.84)	(0.79)
Operating netback	**$ 25.48**	**$ 41.05**
G&A and other (excludes non-cash items)	(2.52)	(3.12)
Finance expenses	(2.13)	(0.51)
Cash flow netback	**20.82**	**37.42**
Depletion and depreciation	(20.67)	(18.88)
Impairment	(5.76)	-
Gain on sale of property and equipment	0.93	-
Accretion	(0.13)	(0.24)
Stock-based compensation	(0.71)	(3.83)
Unrealized gain (loss) on financial instruments	5.55	(3.39)
Deferred income tax	(0.34)	(7.93)
Net Income (loss) netback	**$ (0.31)**	**$ 3.15**

Netbacks decreased by 38% when compared to the year ended 2011. The improvements in operating costs and royalty expenses were offset by a 37% decrease in realized pricing due to lower reference pricing and a widening in the WTI to Edmonton par differential.

Liquidity and Capital Resources

The following table summarizes the change in working capital during the year ended December 31, 2012 and December 31, 2011:

		2012		2011
Working capital (deficit) - beginning of year (1)	$	(34,028,162)	$	(11,472,461)
Cash flow from operating activities		14,588,405		16,341,180
Purchase of property and equipment		(24,448,531)		(64,608,688)
Sale of property and equipment		4,650,000		-
Issuance of shares		2,552,333		25,711,807
Bank Debt		384,113		-
Working capital (deficit) - end of year (1)	$	(36,301,842)	$	(34,028,162)
Credit facility limit	$	42,000,000	$	40,000,000

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

As at December 31, 2012, the Company had a working capital deficit of $36 million (excluding fair value on commodity contracts) which is higher than the working capital deficit of $34 million at December 31, 2012 due to the resumption of the drilling program.

As at December 31, 2012, the $32,138,763 (2011 – $26,245,533) reported amount of bank debt was comprised of $21,950,000 (2011 – $24,450,000) drawn on the revolving operating demand loan, $9,992,093 (December 31, 2011 – $nil) of guaranteed notes and $196,658 (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 December 31, 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 December 31, 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 on the operating demand load, payable monthly, and a credit spread of 2.5% on the guaranteed notes.

Capital Spending

Capital spending is summarized as follows:

	2012	2011
Land and lease rentals	$ 734,910	$ 3,782,231
Drilling and completion	19,727,708	49,808,464
Geological and geophysical	1,002,064	947,870
Equipment	2,812,328	9,487,625
Other Asset Additions	171,521	-
Gross Capital Additions	$ 24,448,531	$ 64,026,190
Disposition of Property and Equipment	(4,650,000)	-
Net Capital Additions	$ 19,798,531	$ 64,026,190

The Company drilled 8 gross (5.0 net) horizontal wells during 2012. The drilling resulted in significant increases in production. The Company completed the sale of a non-core property for $4.7 million in December 2012; the disposition included a well that was drilled in early 2012.

In 2012, the average drill cost per well was $2.0 million and the average completion cost per well was $1.4 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 experienced significant costs saving in the wells drilled later in 2012. The Company is now forecasting a per well drill and complete cost of $2.3 million in Willesden Green and $3.1 million in Ferrier for 2013.

Outlook

The $25 million 2013 capital budget will focus on development of Yangarra's Cardium light oil play with a 4 year inventory indentified. The budget is expected to increase the Company's annual production by 25% to 2,400 boe/d with cash flow from operations estimated at $24 million ($0.20/share) and 2013 debt to cash flow ratio of 1.5. The budget assumes an average price of US$85/bbl of WTI crude oil and an average price of $3.00/mcf of AECO natural gas

Decommissioning Liabilities

As at December 31, 2012, the undiscounted decommissioning obligation associated with the Company's existing properties was estimated to be $6,905,036 for which $5,297,166 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 and truck lease commitment which is accounted for as an operating lease.

Related Party Transactions

During the year ended December 31, 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	2011
Administration and consulting fees	$ 194,960	$ 237,694
Production and capital expenditures	137,846	339,896
	$ 332,806	$ 577,590

Included in accounts payable and accrued liabilities at December 31, 2011 is $11,221 (2011 – $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.

Other long-term liabilities includes a mortgage for $361,411 (December 31, 2011 - $410,000) held in the name of an officer of the Company. The property against which the mortgage is secured is owned by the Company through a trust agreement and is used as a field office. All mortgage payments are made by the Company.

Share Capital

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

	Common Shares	Warrants	Stock Options
Balance - December 31, 2011	**116,607,057**	**8,955,500**	**11,353,800**
Grant of options	-	-	3,155,000
Forfeiture of options	-	-	(2,500,800)
Expiry of options	-	-	(168,000)
Exercise of warrants	5,104,666	(5,104,666)	-
Expiry of warrants	-	(2,430,834)	-
Balance - December 31, 2012	**121,711,723**	**1,420,000**	**11,840,000**
Forfeiture of options	-	-	(305,000)
Balance - Date of MD&A	**121,711,723**	**1,420,000**	**11,535,000**

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 increased the statement of claim based on the information provided by the defendant. The potential outcome of the lawsuit and claims are undetermined, however, they may be material.

In the normal conduct of operations, there are other pending claims by and against the Company. Litigation is subject to many uncertainties, and the outcome of individual matters is not predictable with assurance. In the opinion of management, based on the advice and information provided by its legal counsel, the final determination of these other litigations will not materially affect the Company's financial position or results of operations

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 2011 and 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:

2013	$	244,745
2014	$	241,277
2015	$	241,277

Financial Instruments and Financial Risk Management

The Company's financial instruments include accounts receivable, accounts payable and accrued liabilities, bank debt, other long term liability, 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 commodity contracts are classified as level 2.

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, 2012, the maximum credit exposure is the carrying amount of the accounts receivable of $8,398,042 (2011 – $16,109,194).

The maximum exposure to credit risk for receivables at the reporting date by type of customer was:

Oil and natural gas marketers	$	2,367,306
Joint venture partners		4,873,316
Other		1,157,420
	$	8,398,042

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 January and February 2013.

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 year ended December 31, 2012. The Company would only choose to write-off a receivable balance after all reasonable avenues of collection had been exhausted.

As at December 31, 2012, the Company considers its receivables to be aged as follows:

Not past due	$	5,194,920
Past due by less than 90 days		1,805,871
Past due by more than 90 days		1,397,251
	$	8,398,042

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, as disclosed in note 5 of the consolidated financial statements, 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 and bank debt, which have expected maturities of less than one year resulting in their current classification on the statement of financial position.

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, 2012, if interest rates had been 1% lower with all other variables held constant, earnings for the period would have been $287,000 (2011 - $260,000) 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, 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 December 31, 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. The Company's commodity contracts are discussed in the "commodity price risk contract" section of the MD&A.

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 and debt:

	December 31, 2012	*December 31, 2011*
Shareholders' equity	$ 79,689,765	$ 76,627,244

The Company monitors capital based on annual cash from operations before changes in non-cash working capital 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 cash from operations before changes in non-cash working capital 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, 2012, the Company's capital structure was not subject to external restrictions. No changes have been made to the capital policy since 2011

Selected Historical Financial Information

	2012 Q4($)	2012 Q3($)	2012 Q2($)	2012 Q1($)
Petroleum and natural gas sales	**4,842,343**	4,311,738	5,265,664	6,907,412
Net petroleum and natural gas revenue	**5,055,666**	4,311,406	5,627,535	7,299,772
Net income (loss)	**340,623**	(2,073,174)	3,305,628	(1,790,789)
Net income (loss) per share – basic	**0.00**	(0.02)	0.03	(0.02)
Net income (loss) per share – diluted	**0.00**	(0.02)	0.03	(0.02)
Funds flow from operations	**3,168,328**	2,780,520	3,493,003	5,146,554
Funds flow from operations per share – basic	**0.03**	0.02	0.03	0.04
Funds flow from operations per share –diluted	**0.03**	0.02	0.03	0.04
Net capital expenditures	**4,537,364**	4,679,623	3,006,024	7,575,520

	2011 Q4($)	2011 Q3($)	2011 Q2($)	2010 Q1($)
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	4,262,657	2,844,144
Net loss	(2,155,583)	4,106,091	1,665,821	(2,230,631)
Net loss per share – basic	(0.02)	0.04	0.02	(0.03)
Net 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 –diluted	0.05	0.04	0.03	0.03
Net capital expenditures	19,735,557	19,005,315	7,160,655	18,124,663

Fluctuations in quarterly revenues net income and funds flow from operations over the last eight quarters are due primarily to the volatility in commodity prices and changes in sales volumes due to production growth through successful drilling activity.

Fourth Quarter Activities

Fourth quarter 2012 production of 1,700 boe/d was relatively consistent to the 1,720 boe/d in the comparable period in 2011 however even with the consistent production petroleum and natural gas sales and cash from operations decreased by 32% and 44% respectively when compared to 2011. The decrease is mainly due to realized prices which fell by 28% and liquids which made up 45% of the production in the fourth quarter of 2012 versus 50% in the comparable period in 2011. Production in the month of December 2012 averaged 2,250 boe/d (50% oil and NGL's).

Capital expenditures were $4.5 million in the fourth quarter of 2012 compared to $19.7 million in the same period in 2011. The reduced capital is due to general reductions in costs and reduced drilling because of low natural gas pricing and infrastructure constraints.

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 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 consolidated 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.

<u>Critical judgments in applying accounting policies</u>

CGU Determination

The Company's assets are aggregated into cash-generating-units (CGUs) based on their ability to generate largely independent cash flows and are used for impairment testing. CGUs are determined by similar geological structure, shared infrastructure and geographical proximity.

Impairment indicator assessment

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.

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 estimates of the outcome of future events.

<u>Key sources of estimation uncertainty</u>

Reserves

Reserves 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, 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, and royalties, operating costs, sustaining capital and tax rates. The price used in the Company's 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.

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 assets and certain facilities. 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 income to decrease.

Impairment Estimate

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 the statement of income (loss) and comprehensive income (loss) in the period in which carrying amount exceeded the recoverable amount.

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.

Contingencies

When recognized, management makes its best estimate with respect to future cash outflows.

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 including share price, risk free rate, volatility, expected life and dividend yield. The fair value of commodity contracts is calculated using valuation models that require estimates as to future market prices expected interest rates and expected volatility in these variables. 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..

Accounting standards issued but not yet applied

Certain new standards, interpretations, amendments and improvements to existing standards were issued by the IASB or International Financial Reporting Interpretations Committee ("IFRIC") that are mandatory for accounting periods beginning after January 1, 2013 or later periods. The standards impacted that are applicable to the Company are as follows:

IFRS 9, 'Financial Instruments' was issued in November 2009 as the first step in its project to replace IAS 39 'Financial Instruments: Recognition and Measurement'. IFRS 9 introduces new requirements for classifying and measuring financial assets that must be applied starting January 1, 2015, with early adoption permitted. The IASB intends to expand IFRS 9 during the intervening period to add new requirements for classifying and measuring financial liabilities, de-recognition of financial instruments, impairment and hedge accounting. The Company is currently assessing the impact of this standard.

IFRS 10, 'Consolidated Financial Statements' was issued in May 2011 and will supersede the consolidation requirements in SIC-12 'Consolidation – Special Purpose Entities' and IAS 27 'Consolidated and Separate Financial Statements' effective for annual periods beginning on or after January 1, 2013, with early application permitted. IFRS 10 builds on existing principles by identifying the concept of control as the determining factor in whether an entity should be included within the consolidated financial statements of the parent company. The standard also provides additional guidance to assist in the determination of control where this is difficult to assess. The Company is currently assessing the impact of this standard

IFRS 11, 'Joint Arrangements' was issued in May 2011 and will supersede existing IAS 31, 'Joint Ventures' effective for annual period beginning on or after January 1, 2013, with early application permitted. IFRS 11 provides for the accounting of joint arrangements by focusing on the rights and obligations of the arrangement, rather than its legal form (as is currently the case). The standard also eliminates the option to account for jointly controlled entities using the proportionate consolidation method. The Company is currently assessing the impact of this standard.

IFRS 12, 'Disclosure of Interests in Other Entities' was issued in May 2011 and is a new and comprehensive standard on disclosure requirements for all forms of interests in other entities, including subsidiaries, joint arrangements, associates and unconsolidated structured entities. IFRS 12 is effective for annual periods beginning on or after January 1, 2013, with earlier application permitted. The Company is currently assessing the impact of this standard.

IFRS 13, 'Fair Value Measurement' was issued in May 2011 and sets out in a single IFRS a framework for measuring fair value. IFRS 13 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. This definition of fair value emphasizes that fair value is a market-based measurement, not an entity-specific measurement. In addition, IFRS 13 also requires specific disclosures about fair value measurement. IFRS 13 is effective for annual periods beginning on or after January 1, 2013, with earlier application permitted. The Company is currently assessing the impact of this standard.

IAS 28, 'Investments in Associates and Joint Ventures' – The IASB issued amendments to IAS 28 Investments in Associates and Joint Ventures to coincide with the changes made in IFRS 10 and IFRS 11