Yangarra Resources Ltd.
Management's Discussion and Analysis
For three months ended March 31, 2015

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, 2014 audited consolidated financial statements and the March 31, 2015 unaudited 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 May 14, 2015.

The financial information presented herein has been prepared on the basis of International Accounting Standard 34 ("Interim Financial Reporting"). 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.*

Non–IFRS and Additional IFRS Measures

This document contains "funds from operations", which is an additional IFRS measure presented in the consolidated financial statements. The Company uses funds generated from operations as a key measure to demonstrate the Company's ability to generate funds to repay debt and fund future capital investment. This document also contains the terms "net debt" and "netbacks", which are non-IFRS financial measures. The Company uses these measures to help evaluate its performance. These non-IFRS financial measures do not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures presented by other issuers.

<u>Funds flow from (used in) operations</u>

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 and decommissioning costs incurred. 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 income 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:

	2015 Q1	2014 Q1
Cash from operating activities	$ 6,030,922	$ 6,008,779
Changes in non-cash working capital	3,360,432	4,450,913
Funds flow from operations	$ 9,391,354	$ 10,459,692

<u>*Netbacks*</u>

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 income / (loss) netbacks. Operating netback is calculated as the average sales price of its commodities (including realized gains on financial instruments) 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. 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.

<u>*Net debt*</u>

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.

First Quarter Highlights

- Earnings before interest, taxes, depletion & depreciation, amortization and changes in commodity contracts ("EBITDA") was $9.8 million ($0.17 per share - basic) or $5.6 million including changes in commodity contracts ($0.10 per share - basic).
- Oil and gas sales, after royalties, were $12.3 million with funds flow from operations of $9.4 million ($0.16 per share - basic). This represents a 11% and a 10% decrease, respectively, from the same period in 2014 due to reductions in commodity pricing partially offset by realized hedging.
- As previously disclosed, production was impacted by rolling TCPL sales line shut downs with daily production averaging 2,642 boe/d for the quarter, a 6% decrease from the same period in 2014 and a 13% decrease from the fourth quarter of 2014.
- Net Income of $0.9 million ($0.02 per share - basic) or $1.4 million before tax ($0.02 per share - basic).
- Operating costs were $7.62/boe (including $1.28/boe of transportation costs).
- Operating netbacks, which include the impact of commodity contracts, were $44.00 per boe, a 3% decrease from 2014. Field net backs, which do not include the impact of commodity contracts were $21.05, a decrease of 66% from 2014.
- G&A costs of $2.16/boe.
- Royalties were 6% of oil and gas revenue excluding commodity contracts and 3% of oil and gas revenue including commodity contracts.
- Total capital expenditures were $9.2 million. The Company drilled 2 gross (2.0 net) wells in 2015, made pre-purchases on the Duvernay south block well completion, performed various well optimizations and equipped multiple wells that were producing on flow-back at year-end 2014.
- Net debt, excluding the current portion of the fair value of commodity contracts, was $59.6 million ($55.4 million including the current portion of the fair value of commodity contracts).
- Quarter-end net debt to annualized first quarter cash flow ratio excluding the current portion of the fair value of commodity contracts was 1.6 : 1 (1.5 : 1 including the current portion of the fair value of commodity contracts).

Financial Information

	2015 Q1	2014 Q1
Statements of Comprehensive Income		
Petroleum & natural gas sales and royalty income	$ 7,216,024	$ 16,008,396
Net income (before tax)	$ 1,367,312	$ 1,202,068
Net income	$ 945,117	$ 719,450
Net income per share - basic	$ 0.02	$ 0.01
Net income per share - diluted	$ 0.02	$ 0.01
Statements of Cash Flow		
Funds flow from operating activities	$ 9,391,354	$ 10,459,692
Funds flow from operating activities per share - basic	$ 0.16	$ 0.21
Funds flow from operating activities per share - diluted	$ 0.16	$ 0.21
Cash from operating activities	$ 6,030,922	$ 6,008,779
Statements of Financial Position		
Property and equipment	$ 224,745,569	$ 171,336,343
Total assets	$ 253,362,846	$ 195,777,835
Working capital deficit	$ 55,509,271	$ 62,551,870
Working capital deficit, excluding MTM on commodity contracts	$ 59,625,467	$ 55,822,090
Subordinated Debt	$ -	$ 7,790,145
Non-Current Liabilities	$ 27,736,084	$ 18,246,628
Shareholders equity	$ 148,966,679	$ 97,025,179
Weighted average number of shares - basic	57,755,804	49,136,780
Weighted average number of shares - diluted	58,015,914	50,108,392

Business Environment

	2015 Q1	2014 Q1
Realized Pricing (Including realized commodity contracts)		
Oil ($/bbl)	$ 64.05	$ 92.38
NGL ($/bbl)	$ 43.03	$ 53.32
Gas ($/mcf)	$ 3.36	$ 5.00
Realized Pricing (Excluding commodity contracts)		
Oil ($/bbl)	$ 51.22	$ 98.89
NGL ($/bbl)	$ 34.06	$ 68.74
Gas ($/mcf)	$ 3.07	$ 5.71
Oil Price Benchmarks		
West Texas Intermediate ("WTI") (US$/bbl)	$ 48.57	$ 98.61
Edmonton Par (C$/bbl)	$ 51.85	$ 99.64
Natural Gas Price Benchmarks		
AECO gas (Cdn$/mcf)	$ 2.95	$ 4.76
Foreign Exchange		
U.S./Canadian Dollar Exchange	$ 0.81	$ 0.91

Crude oil prices decreased by 51% for the three months ended March 31, 2015, with the West Texas Intermediate ("WTI") reference price averaging US$48.57/bbl compared with US$98.61/bbl in the same period in 2014 due to slowing global economic conditions outside of the U.S. combined with strong growth in North American crude oil supply. 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 narrowed in the three months ended March 31, 2015 when compared to the same period in 2014, moving from a US$7.94/bbl differential in 2014 to US$6.57/bbl in 2015. In the three months ended March 31, 2015 the US/CDN foreign exchange rate was $0.81 compared to $0.91 for the same period in 2014. The Edmonton par reference price is denominated in Canadian dollars so the change in the foreign exchange rate has increased the Edmonton par price relative to WTI. Edmonton par is the closest reference price point for Yangarra's oil are therefore is the closest proxy to realized pricing.

When compared to 2014 realized pricing on oil decreased by 48%, excluding commodity contracts, and decreased by 31% when the effects of commodity contracts are included. The decrease in oil pricing is a direct result of the decreased WTI pricing.

When compared to 2014 liquids pricing decreased by 50%, excluding commodity contracts, and decreased by 19% when the effects of commodity contracts are included.

During the three months ended March 31, 2015, Yangarra had contracted 300 bbl/day of oil production utilizing WTI fixed price contracts at an average price of C$102.56 per bbl and 500 bbl/d in a costless collar with a floor of C$65.00 WTI/bbl and a ceiling of C$73.50 WTI/bbl. Since the benchmark price was lower than our contracted value the realized prices were positively impacted. As the product is intended to provide protection to both the oil and NGL revenue streams the commodity contracts impact is split between the two products based on their relative production.

AECO natural gas prices decreased for the three months ended March 31, 2015 by 38% to $2.95/mcf from $4.76/mcf in 2014.

Yangarra had contracted 2,000 GJ/day of 2015 natural gas production utilizing AECO fixed price contracts at an average price of $4.11 per GJ. These contracts positively impacted the realized natural gas price.

When compared to 2014 realized pricing on natural gas decreased by 46%, excluding commodity contracts and by 33% when the effects of commodity contracts are included.

Results of Operations

Net petroleum and natural gas production, pricing and revenue

	2015 Q1	2014 Q1
Daily production volumes		
Natural gas (mcf/d)	8,717	7,572
Oil (bbl/d)	783	1,036
NGL's (bbl/d)	363	413
Royalty income		
Natural gas (mcf/d)	196	359
Oil (bbl/d)	0	0
NGL's (bbl/d)	10	25
Combined (boe/d 6:1)	2,642	2,796
Revenue		
Petroleum & natural gas sales - Gross	$ 7,153,174	$ 15,694,979
Royalty income	62,850	313,417
Commodity contract settlement (1)	5,457,741	(1,723,339)
Total sales	12,673,765	14,285,057
Royalty expense	(399,144)	(937,556)
Petroleum & natural gas sales - Net	12,274,621	13,347,501
Change in fair value of contracts	(4,188,208)	(4,403,102)
Total Revenue - Net of royalties	$ 8,086,413	$ 8,944,399

(1) Includes $4 million relating to the monetization of certain commodity contracts in the three months ended March 31, 2015.

Total sales in Q1 2015 decreased by 10% in 2015 to $12.7 million from $14.3 million in the same period 2014. The decrease is attributable to:

- a 52% decrease in average product prices; and
- a 6 % decrease in production (on a boe basis).

The decreased production in 2015 can be attributed to infrastructure constraints due to rolling TCPL sales line shut downs during which TCPL was conducting operations to restore their sales lines to design capacity.

Company Netbacks ($/boe)

	2015 Q1	2014 Q1
Sales price	$ 30.08	$ 62.37
Royalty income	0.26	1.25
Royalty expense	(1.68)	(3.73)
Production costs	(6.34)	(6.49)
Transportation costs	(1.28)	(1.32)
Field operating netback	**21.05**	**52.07**
Commodity contract settlement [1]	22.95	(6.85)
Operating netback	**44.00**	**45.23**
G&A and other (excludes non-cash items)	(2.16)	(1.30)
Finance expenses	(3.92)	(3.33)
Cash flow netback	**37.93**	**40.60**
Depletion and depreciation	(13.90)	(16.53)
Accretion	(0.18)	(0.16)
Stock-based compensation	(0.48)	(1.63)
Unrealized gain (loss) on financial instruments	(17.61)	(17.50)
Deferred income tax	(1.78)	(1.92)
Net Income netback	**$ 3.97**	**$ 2.86**

(1) Includes $4 million relating to the monetization of certain commodity contracts in the three months ended March 31, 2015.

The overall average price earned by the Company was lower when compared to 2014 as natural gas prices decreased by 45% and oil prices decreased by 49%. The average sales price decreased by 52% for the three months ended March 31, 2015 when compared to the same period 2014.

Operating netbacks decreased by 3% when compared to the same period in 2014 with lower realized pricing offset partially by realized hedging gains.

Royalty Income

	2015 Q1	2014 Q1
Royalty income	$ 62,850	$ 313,417

Royalty income decreased in 2015 to $62,850 as no new wells have been drilled on the royalty lands, leaving the existing royalty production subject to regular decline rates and reduced commodity prices. The majority of royalty income is a result of the 15% sliding scale royalty purchased in the Willesden Green area in March 2010. There are currently a total of 12 wells generating the 15% royalty income.

Royalty Expense

	2015 Q1	2014 Q1
Royalty expense	$ 399,144	$ 937,556
Per boe	$ 1.68	$ 3.73
As a % of sales (including commodity contracts)	3%	7%
As a % of sales (excluding commodity contracts)	6%	6%

Royalties decreased to $399,144 for the three months ended March 31, 2015 or 6% as a percentage of sales (excluding commodity contact settlements). The decrease is a result of lower production revenues and a lower commodity price environment as royalty rates are reduced with lower commodity prices.

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

	2015 Q1	2014 Q1
Production costs	$ 1,506,375	$ 1,633,931
Per boe	$ 6.34	$ 6.49
Transportation costs	$ 305,521	$ 333,211
Per boe	$ 1.28	$ 1.32
Combined ($/boe)	$ 7.62	$ 7.82

Production and transportation costs decreased in 2015 to $1,811,896 on a dollar basis and increased by 3% on a per boe basis when compared to 2014 due to reductions in production and lower costs from suppliers in response to the lower commodity pricing.

Depletion, depreciation and accretion

	2015 Q1	2014 Q1
Depletion and depreciation	$ 3,305,544	$ 4,159,286
Per boe	$ 13.90	$ 16.53
Accretion	$ 43,775	$ 41,066

Depletion and depreciation decreased in the first quarter 2015 compared to the same period 2014 due to decreases in production. On a per boe basis, the depletion decreased as the 2014 capital program resulted in a higher reserve base at a lower finding and development cost.

General and administrative expenses ("G&A")

		2015 Q1		2014 Q1
Gross G&A expenses	$	635,353	$	599,603
G&A recoveries		(122,814)		(272,924)
Net G&A expenses	$	512,539	$	326,679
Per boe	$	2.16	$	1.30

On a gross basis, G&A increased by 6% and on a net basis G&A increased by 57% in 2015 when compared to the same period in 2014 due to a decreased drilling program that reduced overhead recoveries. On a per boe basis, G&A increased by 66% when compared to the same period in 2014 due to lower production and reduced overhead recoveries.

Other expenses

		2015 Q1		2014 Q1
Finance				
Interest (includes realized losses on interest rate contracts)	$	558,832	$	593,988
Change in fair value of interest rate contracts		372,212		244,170
Accretion		43,775	$	41,066
	$	974,819	$	879,224
Stock-based compensation	$	114,303	$	410,000

Interest and financing fees for the three months ended March 31, 2015 include interest on the revolving operating demand loan (the average amount drawn in 2015 was $59 million), servicing charges on the demand loan and the change in fair value of the interest rate contracts.

The Company had the following interest rate contracts in place at March 31, 2015:

- Pay a floating rate to receive a 2.35% (plus a 2.50% credit spread) fixed rate on $10 million (January 2015 - June 2018)

- Pay a floating rate to receive a 2.15% (plus a 2.50% credit spread) fixed rate on $10 million (January 2015 - May 2018)

The fair value on the interest rate contracts was in a loss position of $811,999 as at March 31, 2015 (December 31, 2014 – $439,786).

During the three months ended March 31, 2015, the Company granted options to purchase 245,000 common shares, the options will vest equally over three years with the first tranche vesting one year after the grant date. The fair value of the options was estimated at $131,900 ($0.54 per option) using the Black-Scholes pricing model.

Deferred Taxes

	2015 Q1	2014 Q1
Deferred income tax expense	$ 422,195	$ 482,618

The Company's effective tax rate for 2015 was 28%, however, Yangarra did not pay income taxes in 2014 and does not expect to pay income taxes in 2015 as is has sufficient tax pools to cover taxable income.

Commodity price risk contracts

	2015 Q1	2014 Q1
Realized (loss) gain on contract settlement	$ 5,457,741	$ (1,723,339)
Change in fair value of commodity contracts	(4,188,208)	(4,403,102)
	$ 1,269,533	$ (6,126,441)

As at March 31, 2015, the Company was committed to the following commodity price risk contracts for the sale of oil:

<u>2015 Oil</u>
100 bbl/d from January 1 to December 31, 2015 at a fixed price of $86.05 USD/bbl
200 bbl/d from January 1 to December 31, 2015 at a fixed price of $100.00 CDN/bbl
500 bbl/d March 1 to December 31, 2015 in a costless collar with a $65.00 CDN/bbl floor and a $73.50 CDN/bbl ceiling
800 bbl/d May 1 to December 31, 2015 Edmonton par differential swap at $6.75 US/bbl

As at March 31, 2015 the Company was committed to the following commodity price risk contracts on the AECO basis:

<u>2015 Gas</u>
2,000 GJ/d from January 1 to December 31, 2015 at a fixed price of $4.11/GJ

The fair value of the commodity contracts was $4,305,831 as at March 31, 2015 (December 31 2014 – $8,494,039).

The following table summarizes the sensitivity of the fair value of the Company's derivative positions as at March 31, 2015 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 ($0.29/mcf for natural gas and $5.79/bbl for oil). 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	(1,619,488)	848,000
Natural Gas	(209,510)	209,510

Liquidity and Capital Resources

The following table summarizes the change in working capital during the three months ended March 31, 2015 and the year ended December 31, 2014:

		2015		2014
Working capital (deficit) - beginning of period (1)	$	(59,766,933)	$	(36,794,243)
Funds flow from operating activities		9,391,354		38,325,988
Additions to property and equipment		(9,240,302)		(78,125,708)
Additions to E&E Assets		-		(1,680,941)
Issuance of shares		-		26,408,338
Issuance (repayment) of Subordinated Debt		-		(7,786,632)
Decommissioning costs incurred		-		(76,361)
Other Debt		(9,586)		(37,374)
Working capital (deficit) - end of period (1)	$	(59,625,467)	$	(59,766,933)
Subordinated Debt Outstanding	$	-	$	-
Total Debt	$	(59,625,467)	$	(59,766,933)
Current Credit facility limit	$	80,000,000		
Current Subordinated debt facility limit	$	10,000,000		

(1) Excludes current portion of fair value of commodity contracts

As at March 31, 2015, the $62,327,646 (December 31, 2014 – $55,602,093) reported amount of bank debt with Alberta Treasury Branches ("ATB") was comprised of $7,450,000 (December 31, 2014 – $29,150,000) drawn on the revolving operating demand loan, $54,877,646 (December 31, 2014 – $24,940,715) of guaranteed notes and $nil (December 31, 2014 – $1,511,378) of outstanding cheques. The Company is subject to a financial covenant requiring an adjusted working capital ratio above 1 : 1 (current assets plus the undrawn availability under the revolving facility, divided by the current liabilities less the drawn portion of the revolving facility, excluding unrealized commodity contracts and flow-through share premium liability). The Company was in compliance with this covenant as at March 31, 2015. The facility is secured by a general security agreement.

As at March 31, 2015, the maximum amount available under the revolving operating demand loan was $70,000,000 (December 31, 2014 – $70,000,000) at an interest rate of bank prime plus 0.75% per annum on the operating demand loan, payable monthly, or a credit spread of 2.0% on guaranteed notes. A decrease in the borrowing base could result in a reduction to the credit facility, which may require repayment to the lenders. During the period, the weighted average effective interest rate for the bank debt was approximately 3.1% (2014 – 4.1%).

Subsequent to the three months ended March 31, 2015 the Company entered into amended and restated credit facility agreement with ATB the maximum amount available under the revolving operating demand is now $80,000,000.

Subsequent to March 31, 2015 the Company amended the subordinated term loan facility with ATB. The amount available under the facility is now $10 million. The Company must present a drilling schedule to ATB prior to December 31, 2015 to access the funds and once withdrawn the funds are available until April 17, 2017. All other terms remain the same.

The Company is subject to financial covenants on the subordinated term facility requiring an adjusted working capital ratio greater than 1 : 1 (calculation consistent with the calculation disclosed above) and a Debt to EBITDA ratio below 4 : 1 (debt is defined as all obligations, liabilities and indebtedness on the statement of financial position less asset retirement obligation, future income taxes, flow-through share premium liability and commodity\interest contracts and EBITDA is defined as net income plus interest expense and other financing costs, depletion and depreciation and income taxes). In addition the Company is required to comply with a PV-10 proved developed producing ("PDP") to debt ratio of not less than 0.92 : 1 on specified dates and a PV-10 total proved to debt ratio of not less than 1.5 : 1 on specified dates. This facility is secured with a pledge of a general demand debenture and a general security agreement.

The annualized first quarter cash flow ratio as at March 31, 2014 was 1.6 : 1, excluding the current portion of the fair value of commodity contracts (1.5 : 1 including the current portion of the fair value of commodity contracts).

Yangarra intends to fund the 2015 budget with cash flow from operations and the availability on the revolving operating demand loan and the recently announced equity financing. There are no drilling commitments for 2015.

Contractual Obligations and Commitments

As at March 31, 2015	Carrying Amount	Contractual Cash Flows	Less than 1 year	1-2 Years	2-5 Years	More than 5 years
A/P and accrued liabilities	14,142,802	14,142,802	14,142,802	-	-	-
Bank debt [(1)]	62,327,646	62,327,646	62,327,646	-	-	-
Other long-term liabilities	711,289	711,289	-	59,638	651,651	-
Interest rate contract	811,999	811,999	189,635	252,846	369,518	-
Estimated interest payments [(1)]	-	341,071	341,071	-	-	-
	77,993,736	78,334,807	77,001,154	312,484	1,021,169	-

(1) Assumes the revolving credit facility is not renewed May 2015

Capital Spending

Capital spending is summarized as follows:

Cash additions	2015 Q1	2014 Q1
Land, acquisitions and lease rentals	$ 60,502	$ 972,133
Drilling and completion	6,547,532	18,373,739
Geological and geophysical	366,579	320,227
Equipment	2,261,369	2,324,948
Other asset additions	4,320	(1,839)
	$ 9,240,302	$ 21,989,208
Exploration & evaluation assets additions	$ -	$ -

The Company drilled 2 gross (2.0 net) horizontal wells during the three months ended March 31, 2015 at a cost of $3.0 million and $2.3 million, respectively, with the remainder of the drilling, completion and equipment costs coming from pre-purchases for the Duvernay completion, various well optimization procedures and equipping costs on multiple wells that were producing on flow-back prior to year-end 2014.

Outlook

Yangarra continues to manage the balance sheet and is targeting debt to cash flow of 2 to 1 or less in 2015 (assuming current strip pricing). The hedging program has provided excellent coverage in this low commodity environment which together with many other cost cutting initiatives will assist with keeping the balance sheet strong. Yangarra continues to make all capital allocation decisions based on maximizing full cycle economics.

Decommissioning Liabilities

As at March 31, 2015, the undiscounted decommissioning obligation associated with the Company's existing properties was estimated to be $12,415,636 for which $8,881,654 has been recorded using a discount rate of 1.04% - 1.99%, an inflation rate of 2% and an estimated weighted average timing of cash flows of 15 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 months ended March 31, 2015 and 2014 the Company was charged or invoiced the following amounts by certain of its officers and directors through controlled companies:

		2015 Q1		2014 Q1
Administration and consulting fees	$	45,802	$	99,000
Production and capital expenditures		11,146		6,250
	$	56,948	$	105,250

Included in accounts payable and accrued liabilities at March 31, 2015 is $8,159 (December 31, 2014 is $6,478) 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 include a mortgage for $281,585 (December 31, 2014 - $291,172) held in the name of an officer of the Company for a property that is used as a field office. The Company is the beneficial owner through a trust agreement of the property against which the mortgage is secured. 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, 2014	57,755,804	-	4,113,370
Grant of options	-	-	245,000
Balance - March 31, 2015 & Date of MD&A	57,755,804	-	4,358,370

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

2015	$	180,958
2016	$	241,277
2017	$	241,277

Financial Instruments and Financial Risk Management

The Company's financial instruments include accounts receivable, bank debt, subordinated debt, accounts payable and accrued liabilities, other long term liabilities, interest rate contracts and commodity contracts. The carrying values of accounts receivable, accounts payable and accrued liabilities, other long term liabilities and bank debt approximate their fair values due to their relatively short periods to maturity. The fair value of the subordinated debt is approximately equal to the carrying value as the debt is subject to a floating interest rate.

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 the interest rate contracts and the commodity contracts is classified at level 2. The fair value is calculated using the forward price curves as at March 31, 2015 for the period the contract is outstanding.

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 March 31, 2015, the maximum credit exposure is the carrying amount of the accounts receivable of $13,472,560 (December 31, 2014 – $13,609,036) and $4,305,831 of commodity contracts (December 31, 2014 – $8,494,039).

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

Oil and natural gas marketers	$	1,701,642
Joint venture partners		9,475,243
Realized Commodity Contracts		561,145
Other		1,734,530
	$	13,472,560

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 (Computershare). The Company historically has not experienced any significant collection issues with its petroleum and natural gas marketers. All of the revenue accruals and receivables from petroleum and natural gas marketers were received in April 2015.

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 accounts receivable during the year ended March 31, 2015.

As at March 31, 2015, the Company considers its receivables to be aged as follows:

Not past due	$	5,339,363
Past due by less than 90 days		3,464,624
Past due by more than 90 days		4,668,573
	$	13,472,560

b. Liquidity risk

Liquidity risk is the risk that the Company will incur difficulties meeting its financial obligations as they are due. The Company's approach to managing liquidity is to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions without incurring unacceptable losses or risking harm to the Company's reputation. The Company prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. The Company uses authorizations for expenditures on both operated and non-operated projects to further manage capital expenditures.

To facilitate the capital expenditure program, the Company has a credit facility agreement which is regularly reviewed by the lender. The Company monitors its total debt position monthly. The Company also attempts to match its payment cycle with collection of petroleum and natural gas revenues on the 25th of each month. The Company anticipates it will have adequate liquidity to fund its financial liabilities through its future cash flows. The Company's financial liabilities are comprised of accounts payable and accrued liabilities, commodity contracts, interest rate contracts, bank debt and subordinated debt, which are classified as current or non-current on the statement of financial position based on their maturity dates.

The Company intends to fund the 2015 budget with cash flow from operations, the availability on the revolving operating demand loan and the recently announced equity financing. The Company has no drilling commitments for the year ending 2015.

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 and to mitigate this risk, the Company has entered into interest rate contracts. For the three months ended March 31, 2015, if interest rates (not including the effect of the interest rate contract) had been 1% lower with all other variables held constant, income for the period would have been $139,136 (March 31, 2014 - $102,970) higher, due to lower interest expense. An equal and opposite impact would have occurred had interest rates been higher by the same amount.

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 March 31, 2015.

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 commodity price risk contracts are listed in the commodity price risk contracts section.

Capital Resources

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:

	March 31, 2015	*December 31, 2014*
Shareholders' equity	$ 148,966,679	$ 147,838,197
Bank debt	$ 62,327,646	$ 55,602,093

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 March 31, 2015, the Company's capital structure was not subject to external restrictions. No changes have been made to the capital policy in 2015.

Selected Quarterly Financial Information

	2015 Q1($)	2014 Q4($)	2014 Q3($)	2014 Q2($)
Petroleum & natural gas sales and royalty income	7,153,174	10,524,238	14,796,645	14,106,137
Net petroleum and natural gas revenue	6,816,880	9,774,426	13,845,994	13,238,221
Net income	945,117	12,833,554	7,967,369	2,851,233
Net income per share – basic	0.02	0.22	0.14	0.05
Net income per share – diluted	0.02	0.22	0.13	0.05
Funds flow from operations	9,391,354	10,339,008	9,346,927	8,180,361
Funds flow from operations per share – basic	0.16	0.18	0.16	0.15
Funds flow from operations per share –diluted	0.16	0.18	0.16	0.15
Net capital expenditures	9,240,302	18,783,353	19,588,859	19,445,229

	2014 Q1($)	2013 Q4($)	2013 Q3($)	2013 Q2($)
Petroleum & natural gas sales and royalty income	16,008,396	11,265,291	9,568,399	8,113,998
Net petroleum and natural gas revenue	15,070,840	10,708,013	8,866,802	7,837,133
Net income (loss)	719,450	750,851	11,330	2,082,942
Net income (loss) per share – basic	0.01	0.03	0.00	0.06
Net income (loss) per share – diluted	0.01	0.03	0.00	0.06
Funds flow from operations	10,459,692	7,975,588	6,378,207	6,480,689
Funds flow from operations per share – basic	0.21	0.18	0.16	0.15
Funds flow from operations per share –diluted	0.21	0.18	0.16	0.15
Net capital expenditures	21,989,208	23,483,590	8,567,226	3,708,601

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 and declines tied to the timing of drilling activity. The Company has focused capital expenditures on drilling and completions, with major infrastructure costs for a facility built in 2013. Production has grown steadily, with the exception of the first quarter of 2015 due to due to rolling TCPL sales line shut downs. Revenue has grown steadily over the two year period, with the exception of the first quarter of 2015 and the fourth quarter of 2014 due to a significant drop in commodity pricing.

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 and Internal Controls over Financial Reporting

The Company has designed disclosure controls and procedures ("DC&P") to provide reasonable assurance that: (i) material information relating to the Company is made known to Yangarra's CEO and CFO by others within the Company, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

The Company has designed internal controls over financial reporting ("ICOFR") to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company is required to disclose herein any change in the Company's internal controls over financial reporting that occurred during the period beginning on January 1, 2015 and ended on March 31, 2015 that has materially affected, or is reasonably likely to materially affect, the Company's ICOFR.

The Company's CEO and CFO continue to conclude that its DC&P are not operating effectively as a result of the weaknesses in ICOFR discussed hereafter

- Due to the relative small number of employees at Yangarra, Management is aware that there is a lack of segregation of duties relating to complex and non-routine financial and tax issues that may arise. It is not deemed as economically feasible at this time to have such personnel. Yangarra relies on external experts for review and advice on complicated financial and tax issues and for tax planning, tax provision and compilation of corporate tax returns.

These weaknesses in internal controls over financial reporting result in a more than remote likelihood that a material misstatement would not be prevented or detected. Management and the Board of Directors work to mitigate the risk of material misstatement, however, management and the Board of Directors do not have reasonable assurance that this risk can be reduced to a remote likelihood of a material misstatement.

New Accounting Standards

Future Accounting Policy Changes

In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers," which replaces IAS 18 "Revenue," IAS 11 "Construction Contracts," and related interpretations. The standard is required to be adopted either retrospectively or using a modified transition approach for fiscal years beginning on or after January 1, 2018, with earlier adoption permitted. IFRS 15 will be applied by Yangarra on January 1, 2017 and the Company is currently evaluating the impact of the standard on Yangarra's financial statements.

In July 2014, the IASB completed the final elements of IFRS 9 "Financial Instruments." The Standard supersedes earlier versions of IFRS 9 and completes the IASB's project to replace IAS 39 "Financial Instruments: Recognition and Measurement." IFRS 9, as amended, includes a principle-based approach for classification and measurement of financial assets, a single 'expected loss' impairment model and a substantially-reformed approach to hedge accounting. The Standard will come into effect for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. IFRS 9 will be applied by Yangarra on January 1, 2018 and the Company is currently evaluating the impact of the standard on Yangarra's financial statements.

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.

Critical judgments in applying accounting policies

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.

Key sources of estimation uncertainty

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.