Yangarra Resources Ltd.

Management's Discussion and Analysis

For year ended December 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, 2015 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 16, 2016.

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.*

Non–IFRS and Additional IFRS Measures

This document contains "funds flow from (used in) operations", which is an additional IFRS measure. The Company uses funds flow generated from (used in) 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 or adjusted working capital (deficit)" 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.

Funds flow from operations

Yangarra's determination of funds flow from operations and funds flow from operations per share may not be comparable to that reported by other companies. Management uses funds flow from operations to analyze operating performance and leverage, and considers funds flow from 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 operations is calculated using cash from operating activities before changes in non-cash working capital and decommissioning costs incurred. Yangarra presents funds flow from 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 operations to cash from operating activities, which is the most directly comparable measure calculated in accordance with IFRS:

	Year Ended	
	2015	2014
Cash from operating activities	$ 21,449,863	$ 31,663,428
Decommissioning costs incurred	64,178	76,361
Changes in non-cash working capital	(100,640)	6,586,199
Funds flow from operations	$ 21,413,401	$ 38,325,988

Netbacks

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.

Net Debt or adjusted working capital (deficit)

Net debt or adjusted 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 adjusted working capital (deficit).

Adjusted Earnings before interest, taxes, depletion & depreciation, amortization

Adjusted earnings before interest, taxes, depletion & depreciation, amortization ("Adjusted EBITDA") which represents EBITDA, excluding changes in derivative financial instruments are used to assess efficiency, liquidity and the general financial strength of the Company.

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 the Cardium in 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.

2015 Highlights

- Adjusted EBITDA (which excludes changes in derivative financial instruments) was $22.9 million ($0.36 per share - basic).
- Oil and gas sales were $25.1 million with funds flow from operations of $21.4 million ($0.34 per share - basic).
- Net loss of $4.8 million ($0.07 per share - basic) or $3.0 million before tax including a $5.4 million impairment of exploration & evaluation assets in the North Duvernay block.
- Production of 2,392 boe/d.
- Operating costs were $8.98/boe (including $1.59/boe of transportation costs).
- Operating netbacks, which include the impact of commodity contracts, were $29.02 per boe. Field net backs, which do not include the impact of commodity contracts were $18.43.
- G&A costs of $1.91/boe.
- Royalties were 6% of oil and gas revenue excluding commodity contracts and 4% of oil and gas revenue including commodity contracts.
- Total capital expenditures were $40.7 million.
- Raised $20 million of capital in May of 2015
- Net debt (which excludes the current derivative financial instruments) was $60.9 million up from $59.8 million at 2014 year end.

Financial Information

	Year Ended	
	2015	2014
Statements of Comprehensive Income		
Petroleum & natural gas sales	$ 25,138,007	$ 54,582,213
Net income (loss) (before tax)	$ (3,024,696)	$ 33,413,237
Net income (loss)	$ (4,781,170)	$ 24,371,606
Net income (loss) per share - basic and diluted	$ (0.07)	$ 0.45
Statements of Cash Flow		
Funds flow from operations	$ 21,413,401	$ 38,325,988
Funds flow from operating activities per share - basic and diluted	$ 0.34	$ 0.70
Cash from operating activities	$ 21,449,863	$ 31,663,428
Statements of Financial Position		
Property and equipment	$ 243,709,385	$ 218,154,343
Total assets	$ 266,545,156	$ 250,491,053
Working capital deficit	$ 58,848,094	$ 51,399,838
Adjusted working capital deficit (which excludes current derivative financial instruments)	$ 60,886,556	$ 59,766,933
Non-Current Liabilities	$ 30,490,615	$ 26,382,773
Shareholders equity	$ 161,133,141	$ 147,838,197
Weighted average number of shares - basic	63,847,376	54,581,750
Weighted average number of shares - diluted	63,847,376	55,793,173

Business Environment

	Year Ended 2015	Year Ended 2014
Realized Pricing (Including realized commodity contracts)		
Oil ($/bbl)	$ 65.55	$ 84.40
NGL ($/bbl)	$ 30.00	$ 52.93
Gas ($/mcf)	$ 3.28	$ 4.06
Realized Pricing (Excluding commodity contracts)		
Oil ($/bbl)	$ 54.24	$ 88.41
NGL ($/bbl)	$ 22.10	$ 56.50
Gas ($/mcf)	$ 2.85	$ 4.53
Oil Price Benchmarks		
West Texas Intermediate ("WTI") (US$/bbl)	$ 48.76	$ 93.00
Edmonton Par (C$/bbl)	$ 57.60	$ 86.10
Natural Gas Price Benchmarks		
AECO gas (Cdn$/mcf)	$ 2.62	$ 4.50
Foreign Exchange		
U.S./Canadian Dollar Exchange	$ 0.78	$ 0.91

Crude oil prices decreased by 48% for the year ended December 31, 2015, with the West Texas Intermediate ("WTI") reference price averaging US$48.76/bbl compared with US$93.00/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 year ended December 31, 2015 when compared to the same period in 2014, moving from a US$6.66/bbl differential in 2014 to US$3.83/bbl in 2015. In the year ended December 31, 2015 the US/CDN foreign exchange rate was $0.78 compared to $0.91 for 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 and therefore is the closest proxy to realized pricing.

When compared to 2014, realized pricing on oil decreased by 39%, excluding commodity contracts, and decreased by 22% 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 61%, excluding commodity contracts, and decreased by 43% when the effects of commodity contracts are included. Pricing for propane and butane were decreased significantly during the second quarter.

During the year ended December 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 year ended December 31, 2015 by 42% to $2.62/mcf from $4.50/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 37%, excluding commodity contracts and by 19% when the effects of commodity contracts are included.

Results of Operations

Net petroleum and natural gas production, pricing and revenue

	Year Ended	
	2015	2014
Daily production volumes		
Natural gas (mcf/d)	7,722	8,514
Oil (bbl/d)	726	1,022
NGL's (bbl/d)	333	364
Royalty income		
Natural gas (mcf/d)	196	271
Oil (bbl/d)	0	1
NGL's (bbl/d)	13	20
Combined (boe/d 6:1)	2,392	2,870
Revenue		
Petroleum & natural gas sales - Gross	$ 25,138,007	$ 54,582,213
Royalty income	263,004	853,203
Commodity contract settlement (1)	9,258,286	(510,369)
Total sales	34,659,297	54,925,047
Royalty expense	(1,452,385)	(3,505,935)
Total Revenue - Net of royalties	$ 33,206,912	$ 51,419,112

(1) Includes $4 million relating to the monetization of certain commodity contracts in January 2015.

Total sales decreased by 37% in 2015 to $34.7 million from $54.9 million in 2014. The decrease is attributable to:

- a 45% decrease in average product prices; and
- a 17 % 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. The Company drilled 8 gross horizontal wells during 2015.

Company Netbacks ($/boe)

	Year Ended 2015	Year Ended 2014
Sales price	$ 28.77	$ 52.10
Royalty income	0.30	0.81
Royalty expense	(1.66)	(3.35)
Production costs	(7.39)	(6.89)
Transportation costs	(1.59)	(1.58)
Field operating netback	**18.43**	**41.10**
Commodity contract settlement (1)	10.60	(0.49)
Operating netback	**29.02**	**40.62**
G&A and other (excludes non-cash items)	(1.91)	(2.05)
Finance expenses	(2.87)	(2.36)
Funds flow netback	**24.24**	**36.21**
Depletion and depreciation	(13.29)	(15.88)
E&E Impairment	(6.19)	-
Accretion	(0.20)	(0.16)
Stock-based compensation	(0.94)	(0.70)
Unrealized gain (loss) on financial instruments	(7.07)	12.43
Deferred income tax	(2.01)	(8.63)
Net Income (loss) netback	**$ (5.47)**	**$ 23.26**

(1) Includes $4 million relating to the monetization of certain commodity contracts in January 2015.

The overall average price earned by the Company was lower when compared to the year ended December 31, 2015 as natural gas prices decreased by 37%, oil prices decreased by 39% and liquid prices decreased by 61%. The average sales price decreased by 45% for the year ended December 31, 2015 when compared to 2014.

Operating netbacks decreased by 29% for the year ended December 31, 2015 with lower realized pricing offset partially by realized hedging gains.

Royalty Income

	Year Ended 2015	Year Ended 2014
Royalty income	$ 263,004	$ 853,203

Royalty income decreased in 2015 to $263,004 for the year ended December 31, 2015 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

	Year Ended 2015	Year Ended 2014
Royalty expense	$ 1,452,385	$ 3,505,935
Per boe	$ 1.66	$ 3.35
As a % of sales (including commodity contracts)	4%	6%
As a % of sales (excluding commodity contracts)	6%	6%

Royalties decreased to $1,452,385 for the year ended December 31, 2015 or 6% as a percentage of sales (excluding commodity contact settlements). The decrease is a result of lower revenue during the year as the percentage of sales remained relatively constant.

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

	Year Ended 2015	Year Ended 2014
Production costs	$ 6,460,167	$ 7,218,786
Per boe	$ 7.39	$ 6.89
Transportation costs	$ 1,387,628	$ 1,651,072
Per boe	$ 1.59	$ 1.58
Combined ($/boe)	$ 8.98	$ 8.47

Production and transportation costs increased by 6% on a per boe basis when compared to the year ended December 31, 2015 mainly due to the lost production from the TCPL shut-downs. The Company's operating costs are largely fixed and as the TCPL shut-downs are only temporary no changes were made to the fixed operating costs in the field. The Company expects production costs (including transportation costs) to move back down to approximately $8.00/boe once the production is restored.

Depletion and depreciation

	Year Ended 2015	Year Ended 2014
Depletion and depreciation	$ 11,616,421	$ 16,635,642
Per boe	$ 13.29	$ 15.88
Exploration & evaluation asset impairment	$ 5,410,547	$ -

Depletion and depreciation decreased in the year ended December 31, 2015 due to decreases in production. On a per boe basis, the depletion decreased when compared to both periods in 2014 due to lower finding and development costs in 2015.

During 2015, the Company drilled a vertical test well on the North Duvernay land block. Based on the results the Company decided to let the land expire and as a result has recorded an impairment for the drilling costs and land value that was included in E&E assets.

General and administrative expenses ("G&A")

	Year Ended	
	2015	2014
Gross G&A expenses	$ 2,543,453	$ 3,462,309
G&A recoveries	(872,876)	(1,316,433)
Net G&A expenses	$ 1,670,577	$ 2,145,876
Per boe	$ 1.91	$ 2.05

Net G&A decreased by 22% when compared to the year ended December 31, 2014. The decrease is a result of a reduction of contractors and consultants used as senior office personal are replacing the supervisors on drilling and completion operations. The shift has resulted in reduced costs, improved performance and better efficiency on capital projects. Net G&A decreased by 7% on a boe basis when compared to the year ended December 31, 2015 due to lower production and reduced overhead recoveries from a reduced drilling program in 2015.

Other expenses

	Year Ended	
	2015	2014
Finance		
Interest and Finance Expense	$ 2,019,763	$ 1,969,493
Realized losses on interest rate contracts	255,376	107,897
Change in fair value of interest rate contracts	233,235	396,551
Accretion	171,005	170,409
	$ 2,679,379	$ 2,644,350
Stock-based compensation	$ 824,760	$ 734,684

Interest and financing fees for the year ended December 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 December 31, 2015:

- Pay a 2.35% fixed rate (plus a 2.25% credit spread) on $10 million (January 2016 - June 2018).
- Pay a 2.15% fixed rate (plus a 2.25% credit spread) on $10 million (January 2016 - May 2018).

The fair value on the interest rate contracts was in a loss position of $673,022 as at December 31, 2015 (December 31, 2014 – $439,786).

During the year ended December 31, 2015, the Company granted options to purchase 3,646,173 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 $2,278,955 ($0.63 per option) using the Black-Scholes pricing model.

Deferred Taxes

	Year Ended	
	2015	2014
Deferred income tax expense	$ 1,756,474	$ 9,041,631

Yangarra did not pay income taxes in 2015 and does not expect to pay income taxes in 2016 as is has sufficient tax pools to cover taxable income.

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

	Year Ended	
	2015	2014
Canadian oil and gas property expenses	$ 9,153,042	$ 10,247,874
Canadian development expenses	112,753,125	103,782,030
Canadian exploration expenses	16,281,132	15,493,336
Undepreciated capital costs	24,957,432	22,328,502
Non-capital losses (various expiry dates)	1,494,818	1,568,775
Share issuance costs	2,567,243	2,471,312
	$ 167,206,792	$ 155,891,829

Commodity price risk contracts

	Year Ended	
	2015	2014
Realized (loss) gain on contract settlement	$ 9,258,286	$ (510,369)
Change in fair value of commodity contracts	(6,182,129)	13,024,535
	$ 3,076,157	$ 12,514,166

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

2016 Oil

- 400 bbl/d January 1 to December 31, 2016 in a collar with a $73.45 CDN/bbl floor and a $85.00 CDN/bbl ceiling
- 400 bbl/d January 1 to December 31, 2016 Edmonton par differential swap at $3.95 US/bbl

The fair value of the commodity contracts was $2,311,910 as at December 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 December 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 in commodity prices is a reasonable measure ($4.07/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	(848,469)	848,469

Liquidity and Capital Resources

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

		2015		2014
Adjusted Working capital (deficit) - beginning of period	$	(59,766,933)	$	(36,794,243)
Funds flow from operations		21,413,401		38,325,988
Additions to property and equipment		(36,025,121)		(78,125,708)
Additions to E&E Assets		(4,706,547)		(1,680,941)
Issuance of shares		18,731,470		26,408,338
Issuance (repayment) of Subordinated Debt		-		(7,786,632)
Decommissioning costs incurred		(64,178)		(76,361)
Other Debt		(468,648)		(37,374)
Adjusted Working capital (deficit) - end of period	$	(60,886,556)	$	(59,766,933)
Credit facility limit	$	80,000,000	$	70,000,000

As at December 31, 2015, the $62,131,258 (December 31, 2014 – $55,602,093) reported amount of bank debt with Alberta Treasury Branches ("ATB") was comprised of $12,250,000 (December 31, 2014 – $29,150,000) drawn on the revolving operating demand loan, $49,881,258 (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 December 31, 2015. The facility is secured by a general security agreement.

As at December 31, 2015, the maximum amount available under the revolving operating demand loan was $80,000,000 (December 31, 2014 – $70,000,000) at an interest rate of bank prime plus 1.00% per annum on the operating demand loan, payable monthly, or a credit spread of 2.25% 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 3.5% (2014 – 4.1%).

Effective December 31, 2015 an additional $10 million subordinated term facility with Alberta Treasury Branch ("ATB") was not utilized and therefore was terminated as per the agreement.

The Company is in compliance with all covenants as at December 31, 2015.

The Company intends to fund the 2016 budget with cash flow from operations and the availability on the revolving operating demand loan.

Capital Spending

Capital spending is summarized as follows:

Cash additions	Year Ended 2015	2014
Land, acquisitions and lease rentals	$ 1,095,270	$ 1,188,777
Property acquisitions (Farm-in drilling)	1,760,152	2,627,312
Drilling and completion	23,492,434	65,125,540
Geological and geophysical	1,164,679	1,612,737
Equipment	8,307,293	7,569,877
Other asset additions	205,295	1,465
	$ 36,025,123	$ 78,125,708
Exploration & evaluation assets additions	$ 4,706,547	$ -

During 2015, Yangarra drilled 8 gross wells and a vertical test well in the North Duvernay block (which was subsequently impaired).

Outlook

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.

The Company's Board of Directors has approved an initial capital budget of $24 million in 2016.

The capital budget includes drilling of eight Cardium wells in the second half of 2016 and the completion of the standing Duvernay well.

The budget is expected to increase the Company's annual production to 2,750 - 3,000 boe/d with cash flow from operations estimated at $22 million.

The Company expects year-end 2016 debt of $63 million resulting in a debt to annual cash flow ratio of 2.9 to 1 with debt to cash flow improving to less than 2 to 1 on fourth quarter annualized cash flow. The budget assumes an average price of US$42.00/bbl for WTI crude oil (CDN$51.55 bbl Edmonton par) and an average price of $2.00/GJ for AECO natural gas.

Decommissioning Liabilities

As at December 31, 2015, the undiscounted decommissioning obligation associated with the Company's existing properties was estimated to be $13,193,357 for which $9,191,316 has been recorded using a discount rate of 1.04% - 2.21%, 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 lease commitment and truck lease commitment which is accounted for as an operating lease.

Related Party Transactions

During the year ended December 31, 2015 and 2014, the Company was charged or invoiced the following amounts by certain of its officers and directors through controlled companies:

	Year Ended 2015	Year Ended 2014
Administration and consulting fees	$ 430,008	$ 424,085
Production and capital expenditures	128,521	114,291
	$ 558,529	$ 538,376

Included in accounts payable and accrued liabilities at December 31, 2015 is $6,207 (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 $252,228 (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	Stock Options
Balance - December 31, 2014	57,755,804	4,113,370
Equity financing	9,926,000	-
Grant of options	-	3,646,173
Forfeited options	-	(281,455)
Expiry of options	-	(728,388)
Balance - December 31, 2015	67,681,804	6,749,700

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.

Subsequent to December 31, 2015 the above lawsuit and claims were settled.

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.

Contractual Obligations and Commitments

As at December 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	12,322,532	12,322,532	12,322,532	-	-	-
Bank debt (1)	62,131,258	62,131,258	62,131,258	-	-	-
Other long-term liabilities	252,228	252,228	40,583	42,289	137,839	31,517
Commodity Contracts	194,162	194,162	194,162	-	-	-
Interest rate contract	673,022	673,022	273,448	273,448	126,126	-
Estimated interest payments (1)	-	996,689	996,689	-	-	-
Lease agreements for office premises and Vehicles	-	899,252	198,397	198,397	502,457	-
	75,573,202	77,469,143	76,157,069	514,135	766,422	31,517

(1) Assumes the revolving credit facility is not renewed May 2016

The Company satisfied its $2,000,790 CDE commitment in the second quarter of 2015. The Company has spent $8,200,372 of the 12,001,300 CEE commitment and the Company has until the end of 2016 to spend the remaining balance.

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 December 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 December 31, 2015, the maximum credit exposure is the carrying amount of the accounts receivable of $10,281,917 (December 31, 2014 – $13,609,036) and $2,311,910 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:

	2015	2014
Oil and natural gas marketers	$ 1,978,912	$ 2,644,221
Partners on joint operations	5,861,464	8,258,199
Realized commodity contracts	684,955	1,063,489
Other	1,756,586	1,643,127
	$ 10,281,917	$ 13,609,036

Receivables from petroleum and natural gas marketers are typically collected on the 25th day of the month following production. The Company's has mitigated the credit risk associated with the oil and natural gas marketer through a security arrangement with 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 January 2016.

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 December 31, 2015. 90% of the over 90 day receivables are made up of three industry partners. The company has performed an analysis of each partner's financial situation and have determined they have the ability to pay. In addition the Company has the ability, with each of the partners, to withhold production to collect the outstanding balances.

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

	2015	2014
Under 30 days	$ 3,918,880	$ 6,609,455
30 to 60 days	30,585	327,856
60 to 90 days	100,085	3,382,950
Over 90 days	6,232,367	3,288,775
	$ 10,281,917	$ 13,609,036

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 2016 budget with cash flow from operations and the availability on the revolving operating demand loan.

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 year ended December 31, 2015, if interest rates (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 $588,667 (December 31, 2014 - $465,573) 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 December 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.

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:

	December 31, 2015	*December 31,* *2014*
Shareholders' equity	$ 161,133,141	$ 147,838,197
Bank debt	$ 62,131,258	$ 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 December 31, 2015, the Company's capital structure was subject to the banking covenants disclosed in note 5. No changes were made to the capital policy in 2015.

Selected Quarterly Financial Information

	2015 Q4($)	2015 Q3($)	2015 Q2($)	2015 Q1($)
Petroleum & natural gas sales	6,610,187	5,363,673	6,010,973	7,153,174
Net income (loss)	(170,059)	(2,353,636)	(3,202,592)	945,117
Net income per share – basic	(0.00)	(0.03)	(0.05)	0.02
Net income per share – diluted	(0.00)	(0.03)	(0.05)	0.02
Funds flow from operations	4,227,532	4,166,530	3,627,985	9,391,354
Funds flow from operations per share – basic	0.06	0.06	0.06	0.16
Funds flow from operations per share –diluted	0.06	0.06	0.06	0.16
Net capital expenditures	11,449,684	11,706,994	8,260,858	9,240,302

	2014 Q4($)	2014 Q3($)	2014 Q2($)	2014 Q1($)
Petroleum & natural gas sales	10,464,894	14,546,041	13,876,299	15,694,979
Net income (loss)	12,833,554	7,967,369	2,851,233	719,450
Net income (loss) per share – basic	0.22	0.14	0.05	0.01
Net income (loss) per share – diluted	0.22	0.13	0.05	0.01
Funds flow from operations	10,339,008	9,346,927	8,180,361	10,459,692
Funds flow from operations per share – basic	0.18	0.16	0.15	0.21
Funds flow from operations per share –diluted	0.18	0.16	0.15	0.21
Net capital expenditures	18,783,353	19,588,859	19,445,229	21,989,208

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 2015 due to due to rolling TCPL sales line shut downs. Revenue has grown steadily over the two year period, with the exception of 2015 and the fourth quarter of 2014 due to a significant drop in commodity pricing.

Fourth Quarter Activities

Adjusted EBITDA (which excludes changes in derivative financial instruments) was $4.5 million, funds flow from operations was $4.2 million with a net loss of $0.2 million.

Fourth quarter 2015 production of 2,624 boe/d is a decrease of 14% compared to the 3,035 boe/d in the comparable period in 2014. Field netbacks were $15.07/boe, operating netbacks, which includes commodity contracts were $21.80/boe.

Capital expenditures were $11.4 million in the fourth quarter of 2015. During the fourth quarter, the Company drilled and completed two wells and completed three additional wells that were drilled earlier in the year.

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

As at December 31, 2015, an evaluation of the effectiveness of the Company's disclosure controls and procedures, as defined under the rules adopted by the Canadian securities regulatory authorities, was carried out under the supervision and with the participation of Management, including the President and Chief Executive Officer ("CEO"), and the Chief Financial Officer ("CFO"). Based on this evaluation, the CEO and CFO concluded that, as at December 31, 2015, the design and operation of the Company's disclosure controls and procedures were effective to provide reasonable assurance in meeting all regulatory filing requirements.

Internal control over financial reporting means a process designed by, or under the supervision of, an issuer's certifying officers, and effected by the issuer's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP and includes those policies and procedures that:

(a) pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the issuer;

(b) are designed to provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with the issuer's GAAP, and that receipts and expenditures of the issuer are being made only in accordance with authorizations of management and directors of the issuer; and

(c) are designed to provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the issuer's assets that could have a material effect on the annual financial statements or interim financial reports;

Management is responsible for establishing and maintaining adequate internal controls over financial reporting.

Management has conducted an evaluation of its internal controls over financial reporting, and determined that at December 31, 2015 the controls were effective to provide reasonable assurance regarding the reliability of financial reporting, and the preparation of financial statements for external reporting purposes. In May 2013, the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") issued an updated Internal Control-Integrated Framework ("2013 Framework") replacing the Internal Control - Integrated Framework (1992). The control framework Yangarra's officers used to design the Company's ICFR is the 2013 Framework.

During the period beginning on October 1, 2015 and ended on December 31, 2015, there were no material changes to the Company's internal controls over financial reporting, and the CEO and CFO have filed certifications with the Canadian securities regulators regarding the Company's 2015 public filing documents.

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, 2018 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.

IFRS 11 Accounting for Acquisitions of Interests in Joint Operations. The amendments clarify that business combination accounting is required to be applied to acquisitions of interests in a joint operation (e.g. oil and gas property) that constitutes a business. IFRS 11 is effective for annual periods beginning on or after January 1, 2016. Early adoption is permitted. The Company is currently evaluating the impact of adopting IFRS 11

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.

Subsequent event

Subsequent to December 31, 2015 Yangarra closed a property transaction. The reserves associated with the property received were determined by independent reserve engineers. As at January 1, 2016, which is the effective date of the transaction, the reserve category values, using a 10% discount rate ("NPV10"), were as follows:

Reserve Category		NPV10 Value
Proved Developed Producing ("PDP")	$	8,119,000
Total Proved ("TP")	$	22,323,000
Proved + Probable ("2P")	$	36,312,000

The terms of the property transaction included a cash payment by Yangarra of $1.4 million and Yangarra will reduce its accounts receivable by $1.4 million.