Management's discussion and analysis ("MD&A") of the financial condition and the results of operations should be read in conjunction with the audited consolidated financial statements of Yangarra Resources Ltd. (the "Company") for the years ended December 31, 2005 and 2004, together with the accompanying notes. The MD&A has been prepared using information that is current to April 10, 2006.

The financial information presented herein has been prepared on the basis of Canadian generally accepted accounting principles ("GAAP"). Throughout this discussion, percentage changes are calculated using numbers rounded to the decimal to which they appear. All references to dollar amounts are in Canadian dollars.

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

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

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 such events.*

Company History

On November 9, 2005, Yangarra Resources Inc. ("Yangarra") and TriOil Ltd. ("TriOil"), companies related through common directors, completed a non-arm's length amalgamation ("Amalgamation") to form Yangarra Resources Ltd. (the "Company", symbol "YAN"). Pursuant to the Amalgamation, the Company issued 0.95 shares for each outstanding share of Yangarra and 0.95 options each outstanding option of Yangarra, and one share for each outstanding TriOil share, one warrant for each outstanding TriOil warrant, and one option for each outstanding TriOil option. The transaction was accounted for as a purchase with Yangarra deemed the acquirer.

As the Amalgamation was a related party transaction, it was measured at the carrying amount of the net assets acquired, as recorded in the accounts of TriOil. The difference between the carrying amount of the net assets and TriOil's share capital in the amount of $645,323 plus $185,842 of Amalgamation costs incurred by Yangarra (net of tax of $121,690) has been recorded as an adjustment to the Company's deficit.

Predecessor Yangarra was incorporated under the laws of the Province of Alberta on January 22, 1985, as Ayrex Resources Ltd ("Ayrex", symbol AYX). Ayrex subsequently changed its name to Yangarra Resources Inc. and began trading on the TSX Venture Exchange on July 21, 2003. TriOil was formed by the August 13, 2004 amalgamation of Entrada Energy Inc., a private company incorporated on November 16, 2000, and TriOil Ltd., a public company listed on the TSX Venture Exchange and incorporated on July 30, 2002.

Results of Operations

	Three months ended December 31		Year ended December 31	
	2005	2004	2005	2004
Statement of Operations and Deficit				
Petroleum and natural gas sales ($)	3,231,966	1,116,081	8,354,853	3,075,560
Petroleum and natural gas sales per boe ($)	64.89	41.65	55.59	39.75
Net Petroleum and natural gas revenue ($)	2,211,174	700,515	5,533,369	1,817,641
Net petroleum and natural gas revenue per boe ($)	44.40	26.14	36.81	23.49
Daily sales volumes (boe 6:1)	541	291	582	211
Income (loss) for the period ($)	134,136	(22,734)	(266,347)	(791,617)
Income (loss) per share – basic and diluted ($)	–	–	(0.01)	(0.04)
Statement of Cash Flows				
Funds flow from operations ($)	1,472,621	(610,235)	4,008,345	833,524
Weighted average number of shares – basic	42,901,182	24,915,864	31,228,861	21,422,700

As a result of the Amalgamation, the Company increased its working interest in the Medicine Hat area from 50% to 100% and acquired properties in the Inland/Mundare, Jaslan, Provost, Bigstone and Viking South areas of Alberta containing 14 producing wells, excluding Medicine Hat. During 2005, the Company continued exploration and development programs in the Medicine Hat, Mitsue, Grande Prairie, Mega, Ferrier, Inland/Mundare and Jaslan areas of Alberta and in Bayhurst, Saskatchewan. The 2005 drilling program consisted of two gas wells, two oil wells, one reentry and one abandoned well drilled in Ferrier; nine gas wells drilled and tied in at Medicine Hat with one additional well (40%WI) acquired by tieing the well into Company-owned facilities in that area; one oil well drilled and put on stream in Mitsue; a dry and abandoned well drilled at Grande Prairie; one gas well drilled at Jaslan; and one gas well drilled in Bayhurst Saskatchewan.

The three months and year ended December 31, 2005 results of operations are those of Yangarra and include TriOil from November 9 to December, 2005.

Fourth Quarter Results

Net petroleum and natural gas revenue for the three months ended December 31, 2005 was $2,221,174 ($44.40/boe) compared to $700,515 ($26.14/boe) for the 2004 comparative period. The increase is explained by changes in the following components:

- Petroleum and natural gas sales before royalties were $3,231,966 (541 boe/day) for the three months ended December 31, 2005 compared to $1,116,081 (291 boe/day) for the same 2004 quarter. The increase in sales is attributed to an increase in prices from $41.65/boe for the fourth quarter of 2004 to $64.89/boe for 2005 plus an increase in production primarily due to the Amalgamation.
- Royalties, net of the Alberta Royalty Tax Credit, in the fourth quarter of 2005 varied only slightly on both a boe basis and percentage basis from those for 2004. They were $512,813 ($7.59/boe or 16% of sales) for the three months ended December 31, 2005 as compared to $194,606 ($7.26/boe or 17% of sales) for the three months ended December 31, 2004.
- Production and transportation costs were $507,979 ($10.20/boe) for the three months ended December 31, 2005 compared to $220,960 ($8.25/boe) for the same 2004 quarter. The increase in 2005 is due to generally higher industry costs as well as higher costs in a few of the areas acquired through the Amalgamation, including annual lease rentals.

General and administrative expenses for the three months ended December 31, 2005 were $576,767 compared to $422,234 for the three months ended December 31, 2004. The overall increase in general and administrative expenses is commensurate with the increase in the size of the Company since the November Amalgamation, including an increase in leased office space and administrative needs.

Interest expense for the fourth quarter of 2005 was $186,582 compared to $54,992 for 2004. The increase in interest is due to 2005 Part XII.6 interest on unspent flow-through expenditure commitments resulting from flow-through shares issued in 2004 and an increase in the use of the revolving operating demand loan.

Stock-based compensation expense for the fourth quarter of 2005 was a net credit of $3,863 due to the compensation expense related to options granted in 2005 recorded over the options' vesting periods offset by the reversal of previously recorded stock-based compensation expense related to the unvested portion of options cancelled in the quarter. Stock-based compensation expense for the fourth quarter of 2004 was a credit of $297,309 due primarily to year end changes in the estimates used to fair value options granted in prior 2004 quarters.

Depletion and depreciation expense for the three months ended December 31, 2005 was $1,325,376 compared to $855,030 for the three months ended December 31, 2004. The increase is due to increases in the Company's asset base and production volumes, primarily related to the Amalgamation.

Accretion expense for the three months ended December 31, 2005 was a net credit of $18,942 compared to an expense of $3,631 due to the reclassification of asset retirement obligation components related to liability additions that had been recorded as accretion expense in previous 2005 quarters.

Annual Results

Net petroleum and natural gas revenue for the year ended December 31, 2005 was $5,533,369 ($36.81/boe) compared to $1,817,641 ($23.49/boe) for 2004. The increase is explained by changes in the following components:

- Petroleum and natural gas sales before royalties were $8,354,853 (582 boe/day) for the year ended December 31, 2005 compared to $3,075,560 (211 boe/day) for 2004. The increase in sales is attributed to an increase in average prices from $39.75/boe earned in 2004 to $55.59/boe earned in 2005 plus an increase in production primarily due to the results of the Company's drilling program and to the Amalgamation. Production prior to the Amalgamation for the nine months ended September 30, 2005 averaged 368 boe/day compared to 185 boe/day for the same 2004 period.

- Royalties, net of the Alberta Royalty Tax Credit, for all of 2005 were $1,391,569 compared to $620,852 for 2004. As a percentage of sales, royalties decreased slightly from 20% in 2004 to 17% in 2005 due to capital cost adjustments for processing the Crown's portion of gas.
- Production and transportation costs were $1,429,915 ($9.51/boe) for the year ended December 31, 2005 compared to $637,067 ($8.23/boe) for the year ended December 31, 2004. The increase in 2005 is due to generally higher industry costs.

General and administrative expenses for 2005 were $1,152,511 compared to $854,080 for 2004. The increase in general and administrative expenses is commensurate with the overall increase in corporate and production activities plus the increase in the size of the Company since the November Amalgamation, including an increase in leased office space and administrative needs.

Interest expense for the year ended December 31, 2005 was $397,309 compared to $130,037 for 2004. The increase in interest is due to 2005 Part XII.6 interest on unspent flow-through expenditure commitments resulting from flow-through shares issued in 2004 and an increase in the use of the revolving operating demand loan.

Stock-based compensation expense increased from $199,691 in 2004 to $369,628 in 2005 due to an increase in the number of options granted coupled with changes in the assumptions used to estimate the fair value of options plus stock-based compensation related to options acquired through the Amalgamation.

Depletion and depreciation expense for 2005 was $4,144,373 compared to $1,854,858 for 2004. The increase is due to increases in the Company's asset base and production volumes, related to the Company's drilling program and the Amalgamation.

Accretion expense for 2005 was $34,154 compared to $14,525 due to the increase in the number of wells resulting from the Amalgamation and the Company's drilling program.

During the year ended December 31, 2005, the Company generated $4,008,345 of funds flow from operations compared to $833,524 generated in 2004. The improvement in funds flow was due primarily to the increase in net petroleum and natural gas revenues.

Liquidity and Capital Resources

During the three months and year ended December 31, 2005, the Company generated $1,472,621 and $4,008,345, respectively, of funds flow from operations compared to $223,289 and $833,524, respectively, generated in the 2004 comparative periods. The improvement in funds flow was due primarily to the increase in net petroleum and natural gas revenues.

As at December 31, 2005, the Company had a working capital deficit of $12.2 million compared to a deficit of $5.9 million at December 31, 2004. The increase in the working capital deficit was due to a $10.3 million net capital spending program for the year plus $0.3 million of Amalgamation costs and $0.3 million of bank indebtedness acquired from TriOil offset by the $4.0 million of funds flow generated by operating activities and $0.9 million of proceeds from the exercise of warrants. The capital spending program was financed by the $4.0 million funds flow from operations, $0.9 million of warrant proceeds, $4.6 million of proceeds from the revolving operating demand loan and the balance through accounts payable.

In November 2005, the Company revised the credit facilities with its lender, following the Amalgamation. In addition to the $11.5 million revolving operating demand loan facility, the Company has a treasury risk line available for interest rate, foreign exchange and commodity risk management. The treasury risk line is repayable per contract maturities. As at December 31, 2005 and 2004, there were no amounts outstanding under the treasury risk line. Pursuant to the terms of the credit facilities, the Company is subject to a financial covenant with respect to working capital. As at December 31, 2005, the Company was in breach of the covenant and has obtained a letter from the lender acknowledging the breach.

The Company did not engage in any financing activities during 2005. Proceeds from share issuances related to the exercise of warrants issued in 2003. The Company has no off-balance sheet arrangements. Financial instruments consist of those shown on the balance sheet.

Capital Spending

During the three months and year ended December 31, 2005, the Company spent $4,494,023 and $10,573,951 respectively, on its capital spending program compared to $5,290,353 and $14,368,824, respectively, for the three months and year ended December 31, 2004. 2005 capital spending is summarized as follows:

	December 31, 2005	
	Three months ended	Year ended
Land	$ 26,466	$ 331,271
Drilling and completion	2,756,338	6,740,860
Geological and geophysical	808,945	1,260,404
Equipment	890,852	2,162,855
Other	11,422	78,561
	$ 4,494,023	$ 10,573,951

The Company also added $13,929,922 of property and equipment in November 2005 as a result of the Amalgamation.

2005 drilling activity

	Three months ended December 31, 2005		Year ended December 31, 2005	
	Gross	Net	Gross	Net
Light and medium oil	1.0	0.33	3.0	1.20
Natural gas	7.0	3.81	15.0	8.02
Dry	1.0	0.60	2.0	0.92
	9.0	4.74	20.0	10.14

Flow-through expenditures

In November 2004, the Company issued a total of 6,089,741 common shares on a "flow-through" basis at a price of $0.82 per share for gross proceeds of $4,999,998. These proceeds were renounced to investors on December 31, 2004. Approximately $901,532 of related qualifying expenditures were incurred in 2004 and the balance of approximately $4,098,466 was incurred in 2005. In addition, the Company acquired a flow-through commitment of approximately $1,615,081 from TriOil as a result of the Amalgamation. The related qualifying expenditures were incurred in November and December 2005.

Asset retirement obligation

As at December 31, 2005, the undiscounted fair value of the asset retirement obligation associated with the Company's existing properties was estimated to be $2,343,048 for which $1,238,226 has been recorded using a discount rate of 7%, an inflation rate of 2% and an estimated weighted average timing of cash flows of 9.5 years.

Related Party Transactions

The Company's related party transactions consisted of:

a) The Amalgamation, as described under "Corporate History";

b) Amounts charged and/or invoiced by certain of its officers and directors and by companies controlled by certain of the Company's officers and directors:

		2005		*2004*
Administration and consulting fees	$	284,454	$	169,911
Production and capital expenditures	$	293,070	$	2,798,403

c) $103,341 (2004 – $60,746) of fees by a law firm in which a director of the Company is a partner.

Share Capital

In conjunction with the Amalgamation, the Yangarra effected a 0.95 to 1 share consolidation of its share capital. All share capital figures included herein are on a post-consolidation basis.

The Company commenced 2005 with a total of 26,345,166 shares with a book value of $18,665,195. During February, March and July 2005, 2,866,625 warrants were exercised for the same number of common shares for net proceeds of $905,250. In November 2005, the Company issued 24,219,700 shares in the Amalgamation. As at December 31, 2005, there were 53,431,491 issued and outstanding shares with a book value of $31,188,344. Subsequent to year end, 265,500 shares were issued on the exercise of stock options, resulting in 53,696,991 common shares outstanding as of the date of this MD&A.

At the beginning of 2005, there were 1,946,550 stock options outstanding. During the year a total of 1,930,175 options were granted, 2,045,000 options were assumed on the Amalgamation and 671,625 options were cancelled. The resulting number of options outstanding at December 31, 2005 was 5,250,100 of which 3,324,925 were exercisable. Subsequent to year end, an additional 160,000 options were granted, 265,500 options were exercised and 245,625 options were cancelled, resulting in 4,898,975 stock options outstanding as of the date of this MD&A.

At the beginning of 2005, there were 2,866,625 warrants outstanding, all of which were exercised during the year. As a result of the Amalgamation, the Company assumed 1,328,711 warrants, of which 137,049 expired shortly thereafter. As at December 31, 2005, 1,191,662 warrants were outstanding, all of which expired, unexercised, in March 2006. No further warrants have been issued to date.

Commitments

The Company has lease agreements for office premises and equipment with estimated minimum annual payments of $363,597 in 2006, $224,097 in 2007 and $73,708 in 2008.

In January 2006, the Company entered into a six month contract with an investor relations firm at a fee of $5,810 per month (US$5,000), plus expenses. The Company may renew the contract under the same terms for an additional six months with prior written notice.

Outlook

The Company completed its review of all non-core properties in March 2006. Six properties, comprised of Inland/Mundare, Bigstone, Viking South, Provost and Brazeau of Alberta and Bayhurst, Saskatchewan, have been packaged and Kobayashi Partners Limited was retained as of April 10, 2006 to conduct a sale of these properties on behalf of the Company. The properties have a value based on the December 31, 2005 engineering report by Sproule Associates Limited of $9.84 million (based on a 10% discounted net present value after Alberta Royalty Tax Credits and before income taxes) as well as an additional land value of $254,355 on 1535.2 net undeveloped hectares as valued by Seaton Jordan & Associates Ltd. effective December 31, 2005. The properties currently produce 200 boe per day of natural gas and natural gas liquids.

Any proceeds contemplated from the sale of the non-core properties will be utilized for debt reduction. Costs for the 2005 fourth quarter exploration program were substantially higher than management anticipated due to unusually robust price increases for the conduct of field operations. Projected cash flow from petroleum products has been revised downward to approximately $9 million for 2006 from the $12 to $15 million previously forecast by management. This is a result of the significant decline in natural gas prices expected for 2006.

The Company's remaining properties will consist of the core areas of Ferrier, Medicine Hat and Jaslan with non-core properties maintained in Mega and Corbett Creek. The reduction in the number of properties will provide the Company's technical team the opportunity to focus on core areas and reduce exploration costs. In Jaslan, approximately 200 boe per day (net) of gas "behind pipe" in four standing gas wells is expected on stream by mid-summer after the installation of compression and pipelines. The net capital cost of the tie-in is expected to be $1.2 million. An additional $1.5 million is budgeted to drill and tie-in four additional wells in Jaslan in the fourth quarter of 2006. Two earning wells will be drilled in Ferrier in the third quarter which will give the Company a 31.875% working interest in the wells plus a 31.875% working interest in 11 sections of land. An additional two Ferrier wells are planned for the fourth quarter on company-owned property. A budget of $3.6 million is anticipated to drill, case, complete and tie these four wells into company-owned facilities. In addition, third party production volumes are now processed in the 50% owned Ferrier compressor station which will give the Company incremental profit from the Ferrier facility. In Medicine Hat, 20 development locations have been identified, including several farm-in locations which are designed to consolidate the Company's land base in the area. Current plans are to drill 10 wells in the Medicine Hat area in the last half of 2006 with a possibility of increasing that number in the event that natural gas prices improve. The anticipated budget for the drilling, completion and tie-in of these 10 wells is $2.5 million. With two years of shallow gas production history in the Medicine Hat area, the Company is satisfied that the exploration risk is minimal and current fully declined production rates are economic.

Current production rates are stable at 700 boe per day, with production growth dependant on drilling success.

Selected Historical Financial Information

2005	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Petroleum and natural gas revenue	1,496,691	1,655,357	1,970,839	3,231,966
Net petroleum and natural gas revenue	951,744	1,063,878	1,306,573	2,211,174
Net income (loss)	(73,331)	(649,962)	322,810	134,136
Net income (loss) per share	–	(0.02)	0.01	–
Funds from (used in) operations	706,244	822,684	1,006,796	1,472,621
Net capital expenditures	1,968,184	2,931,602	1,180,142	4,494,023

2004	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Petroleum and natural gas sales	369,273	780,177	810,029	1,116,081
Net petroleum and natural gas revenue	186,862	382,629	547,635	700,515
Net income (loss)	(110,402)	(219,041)	(439,440)	(22,734)
Net income (loss) per share	(0.01)	(0.01)	(0.02)	–
Funds from (used in) operations	(8,639)	234,126	384,748	223,289
Net capital expenditures	1,649,160	5,525,542	1,903,769	5,354,219

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. The Company's risk in regards to financial instruments is detailed in note 16 to the annual consolidated financial statements.

Changes in Accounting Policies

The Canadian Institute of Chartered Accountants (CICA) has issued a number of accounting pronouncements, some of which may impact the Company's reported results and financial position in future periods.

Comprehensive Income/Financial Instruments/Hedges

The CICA issued new standards in early 2005 for Comprehensive Income (CICA 1530), Financial Instruments (CICA 3855) and Hedges (CICA 3865), which will be effective for the reporting year-end 2007. The new standards will bring Canadian rules in line with current rules in the US. The standards will introduce the concept of "Comprehensive Income" to Canadian GAAP and will require that an enterprise (a) classify items of comprehensive income by their nature in a financial statement and (b) display the accumulated balance of comprehensive income separately from retained earnings and additional paid-in capital in the equity section of a statement of financial position. Derivative contracts will be carried on the balance sheet at their mark-to-market value, with the change in value flowing to either net income or comprehensive income. Gains and losses on instruments that are identified as hedges will flow initially to comprehensive income and be brought into net income at the time the underlying hedged item is settled. It is expected that this standard will be effective for the Company's 2007 reporting. Any instruments that do not qualify for hedge accounting will be marked-to-market with the adjustment (tax effected) flowing through the income statement.

The Company does not currently have any hedges in place that carry into 2006 or 2007 so there would not be any impact based on the current position.

Disclosure Controls and Procedures

Disclosure controls and procedures have been designed to ensure that information required to be disclosed by the Company is accumulated and communicated to the Company's management as appropriate to allow timely decisions regarding required disclosure. The Company's Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation as of the end of the period covered by the annual filings, that the Company's disclosure controls and procedures as of the end of such period are effective to provide reasonable assurance that material information related to the Company, including its consolidated subsidiaries, is made known to them by others within those entities. It should be noted that while the Company's Chief Executive Officer and Chief Financial Officer believe that the Company's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the disclosure controls and procedures will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.