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, 2006 and 2005, together with the accompanying notes. The MD&A has been prepared using information that is current to April 18, 2007.

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

Yangarra Resources Ltd. (the "Company") was formed by the amalgamation on November 9, 2005, under the Business Corporations Act (Alberta) (the "ABCA"), of Yangarra Resources Inc. ("Predecessor Yangarra") and TriOil Ltd. ("TriOil"). In conjunction with the amalgamation, Predecessor Yangarra effected a 0.95 to 1 consolidation of its equity instruments.

The Company is involved in the production, exploration and development of resource properties. As a result of the amalgamation with TriOil, 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.

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

Results of Operations

	Three months ended December 31			Year ended December 31		
	2006	2005	2004	2006	2005	2004
Statement of Operations and Deficit						
Petroleum & natural gas sales ($)	2,381,251	3,231,966	1,116,081	9,439,251	8,354,853	3,075,560
Petroleum & natural gas sales per boe ($)	44.02	64.89	41.65	43.33	55.59	39.75
Net Petroleum & natural gas revenue ($)	1,905,553	2,211,174	700,515	6,238,311	5,533,369	1,817,641
Net petroleum & natural gas revenue per boe ($)	35.23	44.40	26.14	28.64	36.81	23.49
Daily sales volumes (boe 6:1)	588	541	291	597	412 [(1)]	211
Net income (loss) for the period ($)	(884,912)	134,136	(22,734)	(1,963,139)	(266,347)	(791,617)
Net income (loss) per share – basic ($)	(0.02)	–	–	(0.04)	(0.01)	(0.04)
Statement of Cash Flows						
Funds flow from operations ($)	1,222,746	1,472,621	(610,235)	4,102,713	4,008,345	833,524
Weighted average number of shares – basic	53,989,674	42,901,182	24,915,864	53,759,207	31,228,861	21,422,700

[(1)] In the 2005 MD&A, daily sales volumes for the year was reported as 582 based on predecessor Yangarra production over 365 days and acquired TriOil production from November 9 to December 31 over 52 days. The revised daily sales volume figure is total combined production over 365 days. This revision does not change any previously reported 2005 statistics as they were all based on total volumes, not daily sales volumes.

During the year ended December 31, 2006, the Company continued exploration and development programs in the Ferrier, Medicine Hat, Mega, Inland/Mundare, Jaslan and Corbett Creek areas of Alberta and in Bayhurst, Saskatchewan. The 2006 drilling program resulted in one gas well drilled and cased in Mega; one gas well drilled and cased at Bayhurst; one re-entry and one additional well drilled and cased at Jaslan; two dry and abandoned wells drilled at Mundare; two wells drilled and completed in Ferrier; five wells drilled in Medicine Hat one well drilled and cased in Corbett Creek. In addition, the Company acquired additional acreage in the Corbett Creek, Mundare, Jaslan and Ferrier areas.

Net Petroleum and Natural Gas Revenue

Fourth Quarter Results

Net petroleum and natural gas revenue for the three months ended December 31, 2006 was $1,905,553 ($35.23/boe) compared to $2,221,174 ($44.40/boe) for the 2005 comparative period. The decrease is explained by changes in the following components:

- Petroleum and natural gas sales before royalties were $2,381,251 (588 boe/day) for the three months ended December 31, 2006 compared to $3,231,966 (541 boe/day) for the same 2005 quarter. Although daily production was higher, fourth quarter prices in 2006 decreased to $44.02/boe from $64.89/boe earned in the same quarter of 2005. The decrease in the average price per boe can be attributed to lower oil and natural gas prices as well as to a drop in oil volumes offset by an increase in natural gas volumes.
- Royalties, net of the Alberta Royalty Tax Credit, in the fourth quarter of 2006 were $251,403 ($4.65/boe or 11% of sales) as compared to $512,813 ($7.59/boe or 16% of sales) for the fourth

quarter of 2005. The reduction in royalties on both a percentage and boe-basis relate to production declines in several Medicine Hat wells which resulted in lower royalty rates coupled with the shut-in of the Bigstone well which was at higher average royalty percentage in 2005.

- Production and transportation costs were $224,295 ($4.15/boe) for the three months ended December 31, 2006 compared to $507,979 ($10.20/boe) for the same 2005 quarter. The decrease in 2006 is due to a $214,000 recovery of prior year(s) operating costs resulting from the settlement of a joint venture audit of Ferrier operating costs performed by the Company in 2005. Excluding the recovery, fourth quarter 2006 production and transportation costs were $8.10/boe. In the latter part of 2005, production expenses were higher throughout the industry due to increased demand for services and supplies.

Annual Results

Net petroleum and natural gas revenue for the year ended December 31, 2006 was $6,238,311 ($28.64/boe) compared to $5,533,369 ($36.81/boe) for 2005. The variance is explained by changes in the following components:

- Petroleum and natural gas sales before royalties were $9,439,251 (597 boe/day) for the year ended December 31, 2006 compared to $8,354,853 (412 boe/day – see note below "Results of Operations" table) for 2005. The increase in sales is attributed to an increase in production volumes. However, the average price decreased from $55.59/boe earned in 2005 to $43.33/boe earned in 2006 which can be attributed to a lower average gas price for 2006 marginally offset by an increased oil price in 2006, combined with an increase in gas volumes which made up 83% of production in 2005 to 87% in 2006.
- Royalties, net of the Alberta Royalty Tax Credit, for all of 2006 were $1,335,695 compared to $1,391,569 for 2005. As a percentage of sales, royalties decreased from 17% in 2005 to 14% in 2006 due to reduced production levels on certain wells with higher royalty burdens and the shut-in of the Bigstone well which was at higher average royalty percentage in 2005.
- Production and transportation costs were $1,865,245 ($8.56/boe) for the year ended December 31, 2006 compared to $1,429,915 ($9.51/boe) for the year ended December 31, 2005. The decrease in 2006 is due to a $214,000 recovery of operating costs related to a joint venture audit of Ferrier operating costs performed by the Company in 2005. Excluding the recovery, 2006 production and transportation costs for the year were $9.54/boe.

General and administrative expenses

General and administrative expenses for the three months and year ended December 31, 2006 were $445,555 and $1,287,103, respectively, compared to $576,767 and $1,152,511, respectively, for the three months and year ended December 31, 2005. The decrease in general and administrative expenses in the fourth quarter is due to management's efforts to monitor and reduce costs. The increase for the year is due to the effect of the November 2005 TriOil acquisition still being felt early in 2006, an increase in investor relations activities and a severance payment.

Interest and financing fees

Interest expense for the fourth quarter of 2006 was $236,270 compared to $186,582 for 2005. Interest expense for the year ended December 31, 2006 was $806,013 compared to $397,309 for 2005. The increase in both periods is due to the increase in the use of the revolving operating demand loan and the additional credit facility which increased to $5,000,000 in September 2006 and bears interest at 9%. 2005 interest expense was comprised of Part XII.6 interest on unspent flow-through expenditure commitments resulting from flow-through shares issued in 2004 and interest on the revolving operating demand loan.

Financing fees for the three months and year ended December 31, 2006 were $128,741 and $276,191, respectively, related to the amortization of deferred financing fees incurred to obtain the credit facility. The deferred amounts are amortized to financing fees in the consolidated statement of operations and deficit over the term of the credit facility, which matured in March 2007 (see Liquidity and Capital Resources). The Company also incurred a fee of $11,500 for the renewal of the bank credit facilities in September 2006.

Stock-based compensation

Stock-based compensation ("SBC") for the three months and year ended December 31, 2006 was a $143,372 credit and $251,168 of expense, respectively, compared to a $3,863 credit and $369,628 of expense, respectively for the same 2005 periods. The $143,372 credit in the fourth quarter of 2006 was due to a year-end adjustment to capitalize SBC related to field personnel consistent with the treatment by peer companies. The $3,863 credit in the fourth quarter of 2005 was due to SBC for the period offset by the reversal of previously recorded SBC related to the unvested portion of options cancelled in the quarter. The decrease in total SBC for the year can be attributed to the capitalizing of the portion related to field personnel. Adding back the capitalized portion, total 2006 SBC increased over that for 2005 due to options granted in November 2005 for which a whole year of SBC is included in the 2006 amount as well as SBC related to options granted in 2006.

Depletion, depreciation and accretion

Depletion and depreciation expense for the three months and year ended December 31, 2006 was $1,791,362 ($33.12/boe) and $6,241,307 ($28.65/boe), respectively, compared to $1,325,376 ($26.61/boe) and $4,144,373 ($27.57/boe), respectively for the three months and year ended December 31, 2005. The increase is due to increases in the Company's asset base, production volumes related to the effect of the Company's drilling program whose results did not replace production and to the Amalgamation.

Accretion expense for the three months and year ended December 31, 2006 was $24,029 and $91,118, respectively, compared to a net credit of $18,942 and expense of $34,154, respectively, for the same 2005 periods. The credit in the fourth quarter of 2005 was due to the reclassification of asset retirement obligation components related to liability additions that had been recorded as accretion expense in previous 2005 quarters. The increase in the annual figure is due to an increase in the undiscounted cash flows associated with the retirement of the Company's assets resulting from the increase in the number of properties, and to the reclassification adjustment in 2005.

Impairment loss on goodwill

Goodwill was acquired through the amalgamation between Yangarra and TriOil and represented the excess of the cost over the net of the amounts assigned to assets acquired and liabilities assumed through the August 13, 2004 amalgamation between TriOil and Entrada Energy Inc. As at December 31, 2006, the Company determined that the $396,208 carrying value of goodwill was not recoverable and consequently wrote-off the carrying value as an impairment loss on goodwill in the statement of operations and deficit.

Future income tax recovery

During the year ended December 31, 2006, the Company recorded a $1,137,199 recovery of future income taxes compared to the $271,468 recovery recorded in 2005. The increase in the recovery is due to a reduction in the future tax rate resulting from lower tax rates announced in the 2006 federal and provincial budgets and to the effect of the federal reduction related to the non-deductibility of crown charges and the calculation of resource allowance.

Liquidity and Capital Resources

During the three months and year ended December 31, 2006, the Company generated $1,222,746 and $4,102,713, respectively, of funds flow from operations compared to $1,472,621 and $4,008,345, respectively, generated in the 2005 comparative periods. The decline in funds flow in the fourth quarter is due primarily to the increase in interest expense and financing fees in the period which offset the increase in net petroleum and natural gas revenues and decrease in general and administrative expenses. The improvement for the year is due to the increase in net petroleum and natural gas revenues offset by increases in interest and general and administrative expenses.

In June 2006, the Company obtained a $3,000,000 credit facility with a maturity date of September 15, 2006 at an interest rate of 9%. The $3,000,000 facility was repaid on September 12, 2006 with the proceeds from a new facility negotiated with the same lender. The new credit facility is available to a maximum of $6,000,000, of which $5,000,000 had been drawn by December 31, 2006. The facility matured in March 2007 and the Company has obtained a month-to-month extension to June 30, 2007 for an additional 0.75% per month on the amount of the facility outstanding at the beginning of each month.

In conjunction with the $3,000,000 facility, the Company paid $113,000 of financing fees which were recorded in the consolidated statement of operations and deficit over the term of the facility. Fees related to the $6,000,000 facility totaled $266,441 which have been recorded as deferred financing fees on the balance sheet. Of this amount, $120,000 was paid by the issuance of 292,683 common shares of the Company. Deferred financing fees are amortized over the term of the facility to financing fees on the consolidated statement of operations and deficit. At December 31, 2006, amortization of $151,691 had been recorded to financing fees, resulting in the $114,750 reported carrying value of deferred financing fees.

The Company also has a revolving operating demand loan available to a maximum of $11,500,000, requiring payments of interest only calculated daily and payable monthly at prime plus 0.5. In conjunction with the renewal of the Company's bank facilities in 2006, the Company paid a $11,500 renewal fee which has been included in the amount for financing fees reported in the consolidated statement of operations and deficit.

The Company is subject to financial covenants for working capital, debt to equity and debt to trailing cash flow for the credit facility and a working capital covenant for the revolving operating demand loan. As at December 31, 2006, the Company was in breach of the working capital and debt to trailing cash flow covenants and has obtained letters from both lenders acknowledging and waiving the breaches.

The Company did not engage in any equity financing activities during 2006. Proceeds from share issuances related to the exercise of stock options.

As at December 31, 2006, the Company had a working capital deficit of $17.6 million compared to a deficit of $12.2 million at December 31, 2005. The increase in the working capital deficit was due primarily to a $9.6 million net capital spending program for the year offset by the $4.1 million of funds flow generated by operating activities. The capital spending program was financed by the funds flow from operations plus $5.0 million of proceeds on the credit facility and $0.7 million of proceeds from the revolving operating demand loan.

Capital Spending

During the three months and year ended December 31, 2006, the Company spent $3,032,046 and $9,757,009, respectively, on its capital spending program compared to $4,319,065 and $10,573,951, respectively, for the three months and year ended December 31, 2005. The Company also added $13,929,922 of property and equipment in November 2005 as a result of the Amalgamation.

Capital spending is summarized as follows:

	Three months ended December 31		Year ended December 31	
	2006	2005	2006	2005
Land and lease rentals	$ 39,074	$ 26,466	$ 486,168	$ 331,271
Drilling and completion	1,439,301	2,581,380	4,947,363	6,740,860
Geological and geophysical	279,229	808,945	768,177	1,260,404
Equipment	1,273,770	890,852	3,548,150	2,162,855
Other	672	11,422	7,151	78,561
	3,032,046	4,319,065	9,757,009	10,573,951
Dispositions	–	(300,000)	(207,000)	(300,000)
	$ 3,032,046	$ 4,019,065	$ 9,550,009	$ 10,273,951

2006 drilling activity

	Three months ended December 31, 2006		Year ended December 31, 2006	
	Gross	Net	Gross	Net
Natural gas	5	5.00	12	8.09
Dry	0	0.00	2	0.60
	5	5.00	14	8.69

Asset retirement obligation

As at December 31, 2006, the undiscounted fair value of the asset retirement obligation associated with the Company's existing properties was estimated to be $2,842,306 for which $1,508,698 has been recorded using a discount rate of 7%, an inflation rate of 2% and an estimated weighted average timing of cash flows of 9.8 years.

Related Party Transactions

During the years ended December 31, 2006 and 2005, the Company's related party transactions consisted of:

a)

		2006		*2005*
Administration and consulting fees	$	164,330	$	284,454
Production and capital expenditures	$	324,649	$	293,070

The above amounts were charged or invoiced by certain of its officers and directors and by companies controlled by certain of the Company's officers and directors.

b) $32,299 (2005 – $103,341) of legal fees charged by a law firm in which a director of the Company is a partner.

Share Capital

The Company commenced 2006 with a total of 53,431,491 shares with a book value of $31,188,344. During January and February 2006, 265,500 stock options were exercised for the same number of common shares. In September 2006, the Company issued 292,683 shares as consideration for $120,000 of financing fees related to the Toscana credit facility. As at December 31, 2006, there were 53,989,674 issued and outstanding shares with a book value of $31,474,785. There has been no change in the number of shares outstanding up to the date of this MD&A.

At the beginning of 2006, there were 5,250,100 stock options outstanding, of which 3,324,925 were exercisable. During the year a total of 980,000 options were granted, 265,500 options were exercised and 1,391,650 options were cancelled. The resulting number of options outstanding at December 31, 2006 was 4,572,950 of which 4,370,875 were exercisable. There has been no change in the number of options outstanding up to the date of this MD&A.

At the beginning of 2006, there were 1,191,662 warrants outstanding, all of which expired unexercised in March 2006. No further warrants have been issued to date.

Commitments

In addition to the European Commodity Collars described below, the Company has commitments for leased office premises and equipment with estimated minimum annual payments of $224,097 in 2007 and $73,708 in 2008.

Commodity contracts

a) During 2005, the Company entered into a European Commodity Collar to sell 1000 GJ of gas per day to a third party from May 1, 2005 to December 31, 2005 at a ceiling price of $9 per GJ and a floor price of $7 per GJ. As at December 31, 2005, the Company had fulfilled the terms of the collar.

b) During 2006, the Company engaged in the following put contracts for the sale of natural gas:

- 1,000 GJ per day from October 1 to November 30, 2006 at a strike price of $6.50 per GJ and a premium cost of $0.61 per GJ; and

- 1,000 GJ per day from October 1 to November 30, 2006 at a strike price of $6.50 per GJ and a premium cost of $0.55 per GJ.

As at December 31, 2006, the Company had fulfilled the terms of the put contracts.

c) In February 2007, the Company committed to the following European Commodity Collars for the sale of natural gas:

- 1,000 GJ per day from March 1 to December 31, 2007 at a ceiling price of $10.00 per GJ and a floor price of $7.00 per GJ with a floor premium cost of $0.12 per GJ; and
- 1,000 GJ per day from March 1 to December 31, 2007 at a ceiling price of $8.45 per GJ and a floor price of $7.25 per GJ with a floor premium cost of $0.10 per GJ.

Other financial instruments

At December 31, 2006 and 2005, the carrying amount of cash, accounts receivable, bank indebtedness, bank debt, credit facility and accounts payable and accrued liabilities approximates their fair value due to the short-term maturities of these items.

The Company had no off-balance sheet arrangements at December 31, 2006 and 2005.

The Company's commodity contracts do not meet the criteria for the use of hedge accounting. When such contracts extend over an interim or year end balance sheet date, they are recorded on the balance sheet at the mark-to-market value. Changes in fair value are recognized in income in the period in which the change occurs.

Outlook

The Company was unable to secure an acceptable price for the non core assets for which Kobayashi Partners Limited were retained to market in the first quarter of 2006. The assets were withdrawn from the sales process and Yangarra satisfied its capital requirements for 2006 with cash flow and a mezzanine financing provided by Toscana Capital Corporation ("Toscana"). The original $3.0 million facility due obtained in June 2006 was replaced with a $6.0 million facility in September 2006, against which $5.0 million was drawn. The facility was due March 31, 2007 and has provisions to extend the facility to June 30, 2007. Toscana has agreed to extend the term to April 30, 2007 and perform a monthly review to extend the term to June 30, 2007.

Natural gas prices recovered in the fourth quarter of 2006 and have increased substantially in the first quarter of 2007. This price action, combined with improved production volumes, resulted in significant improvements in net cash flow in the fourth quarter of 2006 which have continued into the first quarter of 2007. The working capital deficit at the end of 2006 was approximately $17.6 million and as of the date of this MD&A, has improved to less than $16 million. Yangarra is looking at several alternatives to pay out the mezzanine debt, including the sale of a property, raising capital or replacing the current debt holder. In addition, the Company has undertaken a review of various expenses in an effort to reduce costs where possible.

Yangarra has significant behind-pipe volumes in Medicine Hat, Ferrier and Jaslan. The estimated behind pipe volume of 300 boe per day will be put onstream once spring breakup is over and capital funds are available. In addition, the Company has identified more than 30 drilling locations in the core areas of Medicine Hat, Ferrier and Jaslan.

Selected Historical Financial Information

2006	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Petroleum and natural gas sales	3,086,261	2,035,958	1,935,781	2,381,251
Net petroleum and natural gas revenue	2,035,418	1,304,724	992,616	1,905,553
Net loss	(295,158)	(109,182)	(673,887)	(884,912)
Net loss per share	(0.01)	–	(0.01)	(0.02)
Funds flow from operations	1,620,312	861,194	398,461	1,222,746
Net capital expenditures	3,383,412	772,324	2,362,227	3,032,046

2005	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Petroleum and natural gas sales	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	1,355,100	4,019,065

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 17 to the annual consolidated financial statements.

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 our 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 December 31, 2006, that the Company's disclosure controls and procedures are effective to provide reasonable assurance that material information related to the Company, is made known to them by others with the entity. It should be noted that while the Company's Chief Executive Officer and Chief Financial Officer believe that our disclosure controls and procedures provide a reasonable level of assurance and 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.

Internal Controls over Financial Reporting

The Chief Executive Officer and Chief Financial Officer of the Company are responsible for designing internal controls over financial reporting or causing them to be designed under their supervision in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. We have assessed the design of our internal control over financial reporting and during this process we have identified certain weaknesses in internal controls over financial reporting which are follows:

- Due to the limited number of staff at the Company, it is not possible to achieve complete segregation of duties; and
- Due to the size of the Company and the limited number of staff, the Company does not have the technical accounting expertise and knowledge to address all complex and non-routine accounting transactions that may arise.

These weaknesses in the Company's 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 in financial reporting. In addition, when complex accounting and technical issues arise during preparation of the quarterly financial statements outside consulting expertise is engaged. In spite of management's best efforts, there can be no assurance that this risk can be reduced to less than a remote likelihood of a material misstatement.

Critical Accounting Estimates

The Company's financial statements are prepared in accordance with Canadian generally accepted accounting principles. A comprehensive discussion of the Company's significant accounting policies is contained in Note 2 to the audited consolidated financial statements for the year ended December 31, 2006. The Company's significant accounting policies are subject to estimates and key judgments about future events, many of which are beyond management's control.

The Company believes the following are the most critical accounting estimates used in the determination of its financial results:

Petroleum and natural gas properties – depletion and ceiling test

The Company follows the full cost method of accounting by initially capitalizing all costs related to the acquisition, development and exploration of petroleum and natural gas reserves. Costs capitalized include land acquisition costs, geological and geophysical expenditures, rentals on undeveloped properties, costs of drilling productive and non-productive wells, together with overhead directly related to exploration and development activities and lease and well equipment. Costs capitalized are deleted using the unit-of-production method based on gross proved petroleum and natural gas reserves as determined by independent qualified reserve evaluators. Production and reserves of petroleum and natural gas are converted to common units of measure based on their relative energy content where one barrel of oil is equivalent to six thousand cubic feet of natural gas. The depletion base excludes the cost of significant unproved properties until it is determined whether proved reserves are attributable to the properties or impairment has occurred.

The Company performs a ceiling test the carrying amount of property and equipment is compared to the sum of the undiscounted cash flows expected to result from the future production of proved and probable reserves and the cost, less any impairment of unproved properties. Estimated cash flows are discounted at the Company's risk-free rate of interest using forecast prices and costs. The carrying amount of undeveloped properties and seismic excluded from the ceiling test are compared to independent evaluations of fair value. Any impairments are recorded as additional depletion expense.

Estimates are the basis for amounts recorded as depletion and the ceiling test. These estimates include proved and probable reserves, production rates, future petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates could be material in future periods.

Asset retirement obligation

The Company recognizes the liability for the asset retirement obligation associated with the abandonment of petroleum and natural gas wells, related facilities, compressors and plants and the removal of equipment from leased acreage and returning such land to its original condition. The fair value the Company's asset retirement obligation is recorded in the period a well or related asset is drilled, constructed or acquired. Fair value is estimated using the present value of the estimated future cash outflows to abandon the assets at the Company's credit-adjusted risk-free interest rate based on the expected timing of such cash outflows. Future costs and their expected timing are estimates that are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates could be material in future periods.

Income taxes

The Company records future tax assets and liabilities to account for the expected future tax consequences of events that have been recorded in its consolidated financial statements and its tax returns. These amounts are estimates and the actual tax consequences may differ from the estimates due to changing tax rates and regimes, as well as changing estimates of cash flows and capital expenditures in current and future periods. A valuation allowance is recorded to the extent that there is uncertainty regarding utilization of future tax assets.

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations, often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability and expense may differ from that estimated and recorded.

Stock-based compensation

Stock-based compensation expense is recorded in the statement of loss and deficit for all options granted based on the estimated fair value at the time of the grant and recognized as expense over the vesting period of the option. The fair value of options is estimated using the Black-Scholes pricing model based on estimates and assumptions for expected life of the options, expected volatility, risk-free interest rate and dividend yield. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates could be material in future periods.

Change in Accounting Policies

The Canadian Institute of Chartered Accountants ("CICA") has issued a number of accounting pronouncements 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 – Recognition and Measurement (CICA 3855), Financial Instruments – Disclosure and Presentation (CICA 3861) and Hedges (CICA 3865), all of which are effective for fiscal periods beginning on or after January 1, 2007.

The standards require the inclusion of all financial instruments on a company's balance sheet at their fair value, other than held-to-maturity investments, loans and receivables. Held-to-maturity investments, loans and receivables would be measured at their amortized cost. The standards create a new statement of comprehensive income that will include changes in fair value of certain derivative financial instruments.

The Company elects to mark-to-market its derivative contracts under its risk management program. The accounting for hedging relationships for prior fiscal years is not retroactively changed. Therefore, management expects no restatement of prior periods as a result of these new standards.

As the Company does not have any hedges in place, this new pronouncement does not impact the Company's current financial position.

International Financial Reporting Standards ("IFRS")

Over the next five years, the CICA will adopt its new strategic plan for the direction of accounting standards in Canada as ratified in 2006. As part of that plan, Canadian accounting standards for public companies will converge with IFRS. The Company will continue to monitor and assess the impact of the planned convergence of Canadian GAAP with IFRS.

Recent Developments

In September 2006, the Alberta government announced that the Alberta Royalty Tax Credit ("ARTC") program for corporations will be discontinued effective January 1, 2007. The ARTC program currently provides oil and natural gas producers a 25% credit against Alberta crown royalties, subject to certain restrictions.