Yangarra Resources Ltd.

Management's Discussion and Analysis

For year ended December 31, 2017

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, 2017 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 8, 2018.

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 2017	2016
Cash from operating activities	$ 51,774,874	$ 16,665,490
Decommissioning costs incurred	95,433	180,862
Changes in non-cash working capital	1,032,343	(582,625)
Funds flow from operations	$ 52,902,650	$ 16,263,727

<u>*Netbacks*</u>

The Company considers corporate netbacks to be a key measure as they demonstrate Yangarra's profitability relative to current commodity prices. Corporate netbacks are comprised of operating, funds flow and net income / (loss) netbacks. Operating netback is calculated as the average sales price of its commodities (including realized gains on financial instruments) and then subtracts royalties, operating costs and transportation expenses. Funds flow netback starts with the operating netback and further deducts general and administrative costs, finance expense and adds finance income. To calculate the net income (loss) netback, Yangarra takes the funds flow netback and deducts share-based compensation expense as well as depletion and depreciation charges, accretion expense, unrealized gains on financial instruments, any impairment or exploration and evaluation expense and deferred income taxes. There is no IFRS measure that is reasonably comparable to netbacks.

<u>*Net debt or adjusted working capital (deficit)*</u>

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).

<u>*Adjusted earnings before interest, taxes, depletion & depreciation, amortization*</u>

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.

2017 Highlights

- Production of 5,740 boe/d an increase of 93% from 2016.
- Oil and gas sales were $77.9 million with funds flow from operations of $52.9 million ($0.66 per share - basic).
- Adjusted EBITDA (which excludes changes in derivative financial instruments) was $54.5 million ($0.68 per share - basic).
- Net income of $19.5 million ($0.24 per share - basic) or $27.3 million before tax.
- Operating costs were $7.77/boe (including $1.03/boe of transportation costs).
- Operating netbacks, which include the impact of commodity contracts, were $27.68 per boe.
- Operating margins were 74% and cash flow margins were 69%.
- G&A costs of $0.95/boe.
- Royalties were 8% of oil and gas revenue.
- Total capital expenditures were $83.5 million.
- Net debt (which excludes the current derivative financial instruments) was $93.5 million.

Fourth Quarter Highlights

- Production of 6,721 boe/d (58% liquids), an increase of 109% from the fourth quarter of 2016.
- Oil and gas sales were $25.2 million with funds flow from operations of $17.6 million ($0.22 per share - basic).
- Adjusted EBITDA (which excludes changes in derivative financial instruments) was $17.5 million ($0.21 per share - basic).
- Net income of $4.7 million ($0.06 per share - basic) or $6.6 million net income before tax.
- Operating costs were $7.46/boe (including $0.97/boe of transportation costs).
- Operating netbacks, which include the impact of commodity contracts, were $30.39 per boe.
- Operating margins were 75% and cash flow margins were 70%.
- G&A costs of $1.44/boe, which includes year-end bonuses.
- Royalties were 9% of oil and gas revenue.
- Total capital expenditures were $31.2 million
- Net Debt to annualized fourth quarter funds flow from operations was 1.33 : 1

Financial Information

	Year Ended		
	2017	2016	2015
Statements of Comprehensive Income			
Petroleum & natural gas sales	$ 77,913,091	$ 29,213,872	$ 25,138,007
Net income (before tax)	$ 27,345,553	$ 10,184,658	$ (3,024,696)
Net income	$ 19,485,327	$ 10,168,751	$ (4,781,170)
Net income per share - basic	$ 0.24	$ 0.14	$ (0.07)
Net income per share - diluted	$ 0.23	$ 0.14	$ (0.07)
Statements of Cash Flow			
Funds flow from operations	$ 52,902,651	$ 16,263,727	$ 21,413,401
Funds flow from operations per share - basic	$ 0.66	$ 0.22	$ 0.34
Funds flow from operations per share - diluted	$ 0.63	$ 0.22	$ 0.34
Cash from operating activities	$ 51,774,874	$ 16,665,490	$ 21,449,863
Statements of Financial Position			
Property and equipment	$ 342,099,959	$ 277,693,631	$ 243,709,385
Total assets	$ 378,231,413	$ 299,046,067	$ 266,545,156
Working capital deficit	$ 11,210,245	$ 66,185,217	$ 58,848,094
Net Debt (which excludes current derivative financial instruments)	$ 93,533,252	$ 65,005,805	$ 60,886,556
Non-Current Liabilities, excluding bank debt	$ 44,366,746	$ 34,156,921	$ 30,490,615
Shareholders equity	$ 207,956,623	$ 184,113,958	$ 161,133,141
Weighted average number of shares - basic	80,719,934	74,635,948	63,847,376
Weighted average number of shares - diluted	84,156,682	75,123,266	63,847,376

Net income for the year ended December 31, 2016 included $13,082,687 from a gain on settlement of a lawsuit.

Business Environment

	Year Ended 2017	2016
Realized Pricing (Including realized commodity contracts)		
Oil ($/bbl)	$ 65.61	$ 58.37
NGL ($/bbl)	$ 35.15	$ 27.08
Gas ($/mcf)	$ 2.46	$ 2.29
Realized Pricing (Excluding commodity contracts)		
Oil ($/bbl)	$ 64.23	$ 54.35
NGL ($/bbl)	$ 33.74	$ 22.51
Gas ($/mcf)	$ 2.25	$ 2.29
Oil Price Benchmarks		
West Texas Intermediate ("WTI") (US$/bbl)	$ 50.84	$ 43.35
Edmonton Par (C$/bbl)	$ 63.20	$ 51.90
Edmonton Par to WTI differential (US$/bbl)	$ 2.18	$ 4.43
Natural Gas Price Benchmarks		
AECO gas (Cdn$/mcf)	$ 2.15	$ 2.15
Foreign Exchange		
U.S./Canadian Dollar Exchange	$ 0.77	$ 0.75

Crude oil prices increased by 18% for the year ended December 31, 2017, with the West Texas Intermediate ("WTI") reference price averaging US$50.84/bbl compared with US$43.35/bbl in the same period in 2016 due to improving global economic conditions combined with strong growth in North American crude oil demand. 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, 2017 when compared to the same period in 2016, moving from a US$4.43/bbl differential in 2016 to US$2.18/bbl in 2017. In the year ended December 31, 2017 the US/CDN foreign exchange rate was $0.77 compared to $0.75 for in 2016. 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 2016, realized pricing on oil increased by 18%, excluding commodity contracts, and increased by 12% when the effects of commodity contracts are included. The change in oil pricing is a direct result of increased production in the fourth quarter when pricing was stronger.

When compared to 2016, liquids pricing increased by 50%, excluding commodity contracts, and increased by 30% when the effects of commodity contracts are included. Pricing for propane and butane improved significantly during 2017.

During the year ended December 31, 2017, Yangarra had contracted 1,100 bbl/day of oil production utilizing WTI fixed price contracts at an average price of C$71.73 per bbl and 200 bbl/d in a costless collar with a floor of C$65.00 WTI/bbl and a ceiling of C$75.00 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 remained constant at $2.15/mcf from 2017 to 2016.

When compared to 2016, realized pricing on natural gas decreased by 2%, excluding commodity contracts and increased by 7% when the effects of commodity contracts are included.

During the year ended December 31, 2017, Yangarra had contracted 4,000 GJ/day of gas production utilizing fixed price contracts at an average price of C$3.06 per GJ

Results of Operations

Net petroleum and natural gas production, pricing and revenue

	Year Ended	
	2017	2016
Daily production volumes		
Natural gas (mcf/d)	14,901	9,586
Oil (bbl/d)	2,295	856
NGL's (bbl/d)	962	503
Combined (boe/d 6:1)	5,740	2,982
Revenue		
Petroleum & natural gas sales - Gross	$ 77,913,091	$ 29,213,872
Realized gain on commodity contract settlement	2,773,986	2,102,795
Total sales	80,687,077	31,316,667
Royalty expense	(6,411,927)	(979,164)
Total Revenue - Net of royalties	$ 74,275,150	$ 30,337,503

Total sales increased by 158% in 2017 to $80.7 million from $31.3 million in 2016. The increase is attributable to:

- a 38% increase in average product prices, largely due to improved liquids
- a 93 % increase in production (on a boe basis)
- $2.8 million from commodity contract settlement in 2017 compared to $2.1 million in 2016

Company Netbacks ($/boe)

	Year Ended 2017	Year Ended 2016
Sales price	$ 37.19	$ 27.00
Royalty expense	(3.06)	(0.90)
Production costs	(6.74)	(7.14)
Transportation costs	(1.03)	(1.31)
Field operating netback	**26.36**	**17.65**
Realized gain on commodity contract settlement	1.32	1.94
Operating netback	**27.68**	**19.59**
G&A	(0.95)	(1.88)
Finance expenses	(1.07)	(2.22)
Funds flow netback	**25.66**	**15.49**
Depletion and depreciation	(10.47)	(13.15)
E&E Impairment	-	(0.70)
Accretion	(0.29)	(0.17)
Stock-based compensation	(0.72)	(0.96)
Unrealized gain (loss) on financial instruments	(1.13)	(3.18)
Gain on Settlement of Lawsuit	-	12.09
Deferred income tax	(3.75)	(0.01)
Net Income netback	**$ 9.30**	**$ 9.40**

The overall average price earned by the Company was higher when compared to the year ended December 31, 2017 as natural gas prices decreased by 2%, oil prices increased by 18% and liquid prices increased by 50%. The average sales price increased by 38% for the year ended December 31, 2017 when compared to 2016.

Operating netbacks increased by 40% for the year ended December 31, 2017 with higher realized pricing and lower operating costs in 2017. Field netbacks increased by 48% for the year ended December 31, 2017.

Royalty Expense

	Year Ended 2017	Year Ended 2016
Royalty expense	$ 6,411,927	$ 979,164
Per boe	$ 3.06	$ 0.90
As a % of sales (including commodity contracts)	8%	3%
As a % of sales (excluding commodity contracts)	8%	3%

Royalties increased to $6,411,927 for the year ended December 31, 2017 or 8% as a percentage of sales, respectively (excluding commodity contact settlements). The increase is a result of pricing increases during 2017 and additional royalties being paid to partners on a variety of new farm-in deals.

Alberta implemented a Modernized Royalty Framework effective January 1, 2017, however Yangarra was granted early opt-in for the 2016 wells. The new framework uses a revenue minus cost royalty structure across all hydrocarbons. A Company will pay a flat royalty rate of 5% on a wells early production until the wells revenue exceeds the Drilling and Completion Cost Allowance ("C*"). C* is based on average industry drilling and completion costs.

Production and Transportation Costs

	Year Ended 2017	Year Ended 2016
Production costs	$ 14,115,307	$ 7,730,777
Per boe	$ 6.74	$ 7.14
Transportation costs	$ 2,159,708	$ 1,418,695
Per boe	$ 1.03	$ 1.31
Combined ($/boe)	$ 7.77	$ 8.46

Production and transportation costs decreased by 8% on a per boe basis when compared to 2016 the decrease is due lower trucking costs, lower maintenance costs and surface locations that are powered using natural gas rather than electricity. Yangarra now has six Company owned trucks and four maintenance trucks which reduce the reliance on third-party trucking, maintenance crews and pressure pumping. A second oil handling facility was constructed during 2017, reducing trucking distances and third-party charges.

Depletion and depreciation

	Year Ended 2017	Year Ended 2016
Depletion and depreciation	$ 21,943,423	$ 14,226,740
Per boe	$ 10.47	$ 13.15
Asset impairment	$ -	$ 756,845

Depletion and depreciation increased in the year ended December 31, 2017 due to increases in production. On a per boe basis, the depletion decreased when compared 2016 due to lower finding and development costs in 2017.

The Company impaired the Jaslan CGU to zero during the three months ended March 31, 2016, management determined that as a result lower natural gas pricing in the quarter the area was no longer economic and therefore disassembled and transported the facility to another CGU.

General and administrative expenses ("G&A")

	Year Ended 2017	Year Ended 2016
Gross G&A expenses	$ 3,004,402	$ 2,507,461
G&A recoveries	(1,017,628)	(472,730)
Net G&A expenses	$ 1,986,774	$ 2,034,731
Per boe	$ 0.95	$ 1.88

G&A decreased by 2% on a net basis and increased by 20% on a gross basis when compared to 2016 due to higher recoveries from an increased drilling program. G&A decreased by 50% on a boe basis due to increased production in 2017 with limited changes to staff.

Other expenses

		Year Ended		
		2017		2016
Finance				
Interest and Finance Expense	$	2,728,223	$	2,186,954
Realized loss on interest rate contract settlement		242,744		275,018
Change in fair value of interest rate contracts		(864,571)		(64,444)
Accretion of decommissioning liability		598,287		182,357
Accretion of debt issue costs		139,744		-
	$	2,844,427	$	2,579,885
Stock-based compensation	$	1,506,330	$	1,041,717

Interest and financing fees for the year ended December 31, 2017 include interest on the revolving operating demand loan (the average amount drawn in 2017 was $75 million), servicing charges on the demand loan and the change in fair value of the interest rate contracts. Included in the financing expense in the year ended December 31, 2017 were the setup fees and legal costs related to the new $120 million syndicated credit facility.

The Company had the following interest rate contracts in place at December 31, 2017:

- Pay a floating rate to receive a 2.35% (plus a 2.50% credit spread) fixed rate on $10 million (January 2018-June 2018)
- Pay a floating rate to receive a 2.15% (plus a 2.50% credit spread) fixed rate on $10 million (January 2018-May 2018)
- Pay a floating rate to receive a 1.945% (plus a 2.50% credit spread) fixed rate on $10 million (June 2018-November 2023)
- Pay a floating rate to receive a 1.935% (plus a 2.50% credit spread) fixed rate on $10 million (May 2018-November 2023)

The fair value on the interest rate contracts was in a gain position of $255,993 as at December 31, 2017 (December 31, 2016 – loss position of $608,578).

During the year ended December 31, 2017, the Company granted options to purchase 1,558,342 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 $2,561,675 ($1.64 per option) using the Black-Scholes pricing model.

Deferred Taxes

	Year Ended 2017	Year Ended 2016
Deferred income tax expense	$ 7,860,226	$ 15,907

Yangarra did not pay income taxes in 2017 and does not expect to pay income taxes in 2018 as it has sufficient tax pools to cover taxable income.

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

	Year Ended 2017	Year Ended 2016
Canadian oil and gas property expenses	$ 17,901,536	$ 13,175,918
Canadian development expenses	145,204,242	123,495,023
Canadian exploration expenses	17,525,193	16,852,743
Undepreciated capital costs	26,209,276	21,871,554
Non-capital losses (various expiry dates)	1,279,705	1,298,458
Share issuance costs	1,466,735	2,419,219
	$ 209,586,687	$ 179,112,915

Commodity price risk contracts

	Year Ended 2017	Year Ended 2016
Realized gain on commodity contract settlement	$ 2,773,986	$ 2,102,795
Change in fair value of commodity contracts	(2,373,629)	(3,446,142)
	$ 400,357	$ (1,343,347)

As at December 31, 2017 the Company was committed to the following commodity price risk contracts in place:

Year	Volume	Term	Reference	Type	Strike Price
Oil					
2018	200 bbl/d	Jan to Dec	CDN$ WTI	Collar	CDN$ 62.50/bbl-75.90/bbl
2018	300 bbl/d	Jan to Jun	CDN$ WTI	Collar	CDN$ 62.50/bbl-76.10/bbl
2018	300 bbl/d	Jan to Dec	CDN$ WTI	Swap	CDN$ 71.60/bbl
2018	300 bbl/d	Jan to Jun	CDN$ WTI	Swap	CDN$ 75.17/bbl
2018	300 bbl/d	Jan to Jun	US$ WTI	Swap	US$ 49.10/bbl
2018	300 bbl/d	Jan to Jun	US$ WTI	Swap	US$ 52.15/bbl
2018	300 bbl/d	Jan to Jun	US$ WTI	Swap	US$ 56.75/bbl
2018	200 bbl/d	Jan to Dec	US$ WTI	Sold Call	US$ 70.00/bbl
2018	300 bbl/d	Jul to Dec	CDN$ WTI	Sold Call	CDN$ 75.17/bbl
2019	500 bbl/d	Jan to Dec	US$ WTI	Sold Call	US$ 60.00/bbl
2019	200 bbl/d	Jan to Dec	US$ WTI	Sold Call	US$ 65.00/bbl
Propane					
2018	200 bbl/d	Jan to Dec	Conway - C3	Swap	USD$32.34

The following contracts were entered into after December 31, 2017:

Year	Volume	Term	Reference	Type	Strike Price
Oil					
2018	200 bbl/d	Jul to Dec	US$ WTI	Collar	US$ 55.00/bbl-64.40/bbl
2018	300 bbl/d	Feb to Jun	US$ WTI	Swap	US$61.00
2018	300 bbl/d	Jul to Dec	CDN$ WTI	Swap	CDN$ 75.40/bbl
2018	300 bbl/d	Jul to Dec	CDN$ WTI	Swap	CDN$ 75.40/bbl
2018	300 bbl/d	Jul to Dec	CDN$ WTI	Swap	CDN$ 76.00/bbl
2018	300 bbl/d	Mar to Dec	CDN$ WTI	Swap	CDN$ 78.20/bbl

The fair value of the commodity contracts was in a loss position of $3,507,861 as at December 31, 2017 (December 31, 2016 – loss of $1,134,232).

The following table summarizes the sensitivity of the fair value of the Company's derivative positions as at December 31, 2017 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 ($5.96/bbl for oil). Fluctuations in commodity prices potentially could have resulted in unrealized gains (losses) impacting income before tax as follows:

	Impact on Income Before Tax	
	Increase 10%	Decrease 10%
Crude oil	$ (2,685,873)	$ 1,785,772

Liquidity and Capital Resources

The following table summarizes the change in working capital during the year ended December 31, 2017 and December 31, 2016:

		2017		2016
Net Debt - beginning of period	$	(65,005,805)	$	(60,886,556)
Funds flow from operations		52,902,650		16,263,727
Additions to property and equipment		(83,472,094)		(27,672,766)
Property Acquisition		-		(3,707,693)
Decommissioning costs incurred		(95,433)		(180,862)
Issuance of shares		2,179,593		11,218,610
Other Debt		(42,163)		(40,265)
Net Debt - end of period	$	(93,533,252)	$	(65,005,805)
Credit facility limit	$	120,000,000	$	80,000,000

As at December 31, 2016, the Company had a $80 million revolving operating demand loan in place with Alberta Treasury Branches with $65 million drawn.

On May 12, 2017, Yangarra repaid the $72 million drawn on the revolving operating demand loan and entered into a $100 million syndicated credit facility. The banking syndicate is led by Alberta Treasury Branches and includes Canadian Imperial Bank of Commerce. On November 16, 2017 the syndicated credit facility was increased to $120 million and National Bank of Canada was added.

As at December 31, 2017, the maximum amount available under the syndicated credit facility was $120 million comprised of a $110 million extendible revolving term credit facility and a $10 million operating facility. The amount available under these facilities is re-determined at least twice a year and is primarily based on the Company's oil and gas reserves, the lending institution's forecast commodity prices, the current economic environment and other factors as determined by the syndicate of lending institutions. If the total advances made under the credit facilities are greater than the re-determined Borrowing Base, the Company has 60 days to repay any shortfall. The initial maturity date of the facility is May 31, 2019 (the "Initial Maturity Date") and the next borrowing base review is scheduled for May 31, 2018. The Initial Maturity Date may be extended for 364 day periods pursuant to delivery of a request for extension by the Company within certain time periods specified in the syndicated credit facility agreement.

As at December 31, 2017, the $84,886,124 (2016 – $65,140,999) reported amount of bank debt was comprised of $412,132 drawn on the operating facility, $84,821,111 drawn on the extendible revolving term credit facility in bankers' acceptance and net of debt issue costs of $347,119.

The Company is subject to a single 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 obligation). The Company was in compliance with this covenant as at December 31, 2017. The facility is secured by a general security agreement over all assets of the Company.

The total stamping fees range, depending on the debt to EBITDA ratio, between 100 bps to 250 bps on bank prime borrowings and between 200 bps and 350 bps on bankers' acceptances. The undrawn portion of the credit facility is subject to a standby fee in the range of 50 bps to 87.5 bps. During the year ended December 31, 2017, the weighted average effective interest rate for the bank debt was 3.19% (2016 – 3.31%).

Capital Spending

Capital spending is summarized as follows:

	Year Ended	
Cash additions	2017	2016
Land, acquisitions and lease rentals	$ 7,164,597	$ 2,079,149
Cash property acquisitions	-	1,400,000
Drilling and completion	64,309,093	19,075,429
Geological and geophysical	824,760	913,996
Equipment	10,853,654	4,085,067
Other asset additions	319,990	119,125
	$ 83,472,094	$ 27,672,766
Exploration & evaluation assets	$ (729,600)	$ -

The Company drilled and completed sixteen (16) wells in the bioturbated Cardium formation in 2017, five (5) wells were drilled prior to spring breakup and 11 wells were drilled post breakup with an additional two wells drilling over year-end.

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 $90 million for 2018. The 2018 capital budget includes the drilling of seven (7) new wells in the first quarter and fifteen (15) new wells in the second half.

The budget is expected to increase the Company's annual 2018 production to 9,000 – 10,000 boe/d with cash flow from operations estimated at $80 to $90 million.

The Company expects year-end 2018 net debt of $95 – $105 million resulting in a debt to annual cash flow ratio of 1.1 – 1.3 to 1. The budget assumes an average price of US$55.00/bbl for WTI crude oil (CDN$63.75/bbl Edmonton par) and an average price of $2.00/GJ for AECO natural gas

Decommissioning Liabilities

As at December 31, 2017, the undiscounted decommissioning obligation associated with the Company's existing properties was estimated to be $12,175,616 for which $10,076,055 has been recorded using a discount rate of 1.31% - 2.47%, an inflation rate of 2% and an estimated weighted average timing of cash flows of 10 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, 2017 and 2016, the Company was charged or invoiced the following amounts by certain of its officers and directors and by companies controlled by certain of the Company's officers and directors:

	Year Ended 2017	Year Ended 2016
Administration and consulting fees	$ 557,917	$ 308,785
Production and capital expenditures	364,175	504,380
	$ 922,092	$ 813,165

Included in accounts payable and accrued liabilities at December 31, 2017 is $23,193 (December 31, 2016 - $6,986) relating to the above transactions. These transactions were in the normal course of operations and were measured at fair value. Other long-term liabilities include a mortgage for $169,799 (December 31, 2016 - $211,962) 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, 2016	79,815,811	7,888,198
Grant of options	-	1,558,342
Forfeited options	-	(20,000)
Exercise of options	1,562,679	(1,562,679)
Balance - December 31, 2017	81,378,490	7,863,861

Contingency

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, 2017 the contractual maturities of the Company's obligations are as follows:

	Carrying Amount	Contractual Cash Flows	Less than 1 year	1-2 Years	2-5 Years	More than 5 years
Accounts payable and accrued liabilities	38,421,687	38,421,687	38,421,687	-	-	-
Bank debt	84,886,124	84,886,124	-	84,886,124	-	-
Other long-term liabilities	169,798	169,798	43,488	45,431	80,879	-
Commodity contracts	3,507,861	3,507,861	2,532,196	975,665	-	-
Interest rate contract	68,037	68,037	68,037	-	-	-
	127,053,507	127,053,507	41,065,408	85,907,220	80,879	-

The Company has entered into lease agreements for office premises and Company vehicles with payments as follows:

2018	$	543,503
2019	$	512,187
2020	$	480,965
2021	$	232,716
Thereafter	$	72,616

Financial Instruments and Financial Risk Management

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 partners on joint operations 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, 2017, the maximum credit exposure is the carrying amount of the accounts receivable of $26,413,976 (December 31, 2016 – $11,225,201). The maximum exposure to credit risk for accounts receivable as at December 31, 2017 and December 31, 2016 by type of customer was:

	December 31, 2017	December 31, 2016
Natural gas and liquids marketers	$ 12,737,640	$ 3,479,225
Partners on joint operations	11,159,533	6,781,799
Realized commodity contracts	67,093	16,033
Other	2,449,710	948,144
	$ 26,413,976	$ 11,225,201

Receivables from natural gas and liquids marketers are typically collected on the 25th day of the month following production. The Company has mitigated the credit risk associated with the natural gas and liquids marketer through a security arrangement with Computershare. The Company historically has not experienced any significant collection issues with its natural gas and liquids marketers. All the revenue accruals and receivables from natural gas and liquids marketers were received in January 2017.

Receivables from partners on joint operations are typically collected within one to three months of the bill being issued to the partner. The Company mitigates the risk from receivables from partners on joint operations 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 partners on joint operations as disagreements occasionally arise which increases the potential for non-collection. For properties that are operated by the Company, production can be withheld from partners on joint operations who are in default of amounts owing. In addition, the Company often has offsetting amounts payable to partners on joint operations from which it can net receivable balances.

As at December 31, 2017 and December 31, 2016, the Company considers its receivables to be aged as follows

	December 31, 2017	December 31, 2016
Under 30 days	$ 17,449,229	$ 4,979,900
30 to 60 days	2,003,025	116,009
60 to 90 days	168,871	85,308
Over 90 days	6,792,851	6,043,984
	$ 26,413,976	$ 11,225,201

90% of the over 90-day receivables are made up of two industry partners. The Company has performed an analysis of each partner's financial situation and have determined they have the ability to pay. Included in the over 90-day receivables are balances with a significant portion in dispute with two of the industry partners (see note 16). The Company did not provide for any doubtful accounts nor write-off any accounts receivable during the year ended December 31, 2017.

Risk management assets and liabilities consist of commodity contracts used to manage the Company's exposure to fluctuations in commodity prices. The Company manages the credit risk exposure related to risk management contracts by selecting investment grade counterparties and by not entering into contracts for trading or speculative purposes. During 2017 and 2016, the Company did not experience any collection issues with risk management contracts. The Company typically does not obtain or post collateral or security from its oil and natural gas marketers or financial institution counterparties. The carrying amounts of accounts receivable represent the maximum credit exposure

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 and availability on bank facilities. The Company's financial liabilities are comprised of accounts payable and accrued liabilities, interest rate contracts, commodity contracts, other long-term liabilities and bank debt, which are classified as current or non-current on the consolidated statement of financial position based on their maturity dates.

The Company has been funding the 2018 budget with cash flow from operations and the $35 million available on credit facility (see note 5).

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, 2017, 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 $855,766 (2016 - $643,881) 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, 2017.

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, 2017	*December 31,2016*
Shareholders' equity	$ 207,956,624	$ 184,113,958
Bank debt	$ 85,233,243	$ 65,140,999

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 debt available from the Company's lender, the level of bank debt 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, 2017, the Company's capital structure was subject to the banking covenants disclosed in note 5. No changes were made to the capital policy in 2017.

Selected Quarterly Financial Information

	2017 Q4($)	2017 Q3($)	2017 Q2($)	2017 Q1($)
Petroleum & natural gas sales	25,172,383	17,663,925	19,527,395	15,549,388
Net income (loss)	4,681,958	3,975,606	5,611,218	5,216,545
Net income (loss) per share – basic	0.06	0.05	0.07	0.07
Net income (loss) per share – diluted	0.05	0.05	0.07	0.06
Funds flow from operations	17,563,628	12,948,149	12,047,670	10,343,203
Funds flow from operations per share – basic	0.22	0.16	0.15	0.13
Funds flow from operations per share –diluted	0.20	0.15	0.14	0.12
Net capital expenditures	31,164,275	20,910,525	7,901,032	23,496,262

	2016 Q4($)	2016 Q3($)	2016 Q2($)	2016 Q1($)
Petroleum & natural gas sales	11,149,691	5,988,310	5,729,668	6,346,203
Net income (loss)	(339,197)	(470,783)	(899,623)	11,878,454
Net income (loss) per share – basic	(0.00)	(0.01)	(0.01)	0.18
Net income (loss) per share – diluted	(0.00)	(0.01)	(0.01)	0.18
Funds flow from operations	6,781,301	3,331,966	2,791,331	3,359,129
Funds flow from operations per share – basic	0.09	0.04	0.04	0.05
Funds flow from operations per share –diluted	0.09	0.04	0.04	0.05
Net capital expenditures	13,672,922	10,436,072	2,358,275	4,913,122

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. Production has grown steadily, with significant increases starting with the fourth quarter of 2016 due to a positive change in the productivity of the new wells.

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, 2017, 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, 2017, 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 Generally Accepted Accounting Procedures ("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, 2017 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, 2017 and ended on December 31, 2017, 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 2017 public filing documents.

New Accounting Standards

There were no new accounting standards adopted by the Company for the year ended December 31, 2017. A description of accounting standards that will be effective in the future is included in the notes to the Company's audited Consolidated Financial Statements as at and for the year ended December 31. 2017.

Accounting standards issued but not yet applied

IFRS 16 Leases issued on January 13, 2016 by the IASB replaces IAS 17 Leases. The new standard introduces a single recognition and measurement model for leases, which would require the recognition of assets and liabilities for most leases with a term of more than twelve months. The new standard is effective for annual periods beginning on or after January 1, 2019. Early adoption is permitted for entities that apply IFRS 15 "Revenue from Contracts with Customers" at or before the initial adoption date of January 1, 2018. Management is currently assessing any potential impact of the adoption of IFRS 16.

In April 2016, the IASB issued its final amendments to 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 retrospective approach for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. IFRS 15 will be applied by Yangarra on January 1, 2018. The Company expects no material impact on net income or the statements of financial position and the Company will add the required note disclosure.

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 the Company on January 1, 2018. The Company expects no material impact on net income or the statements of financial position and the Company will add the required note disclosure.

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

Business combinations

Determination of the fair value of acquired assets and liabilities in a business combination requires management to make assumptions and estimates about future events. The fair value of crude oil and natural gas interests is estimated with reference to the discounted cash flows expected to be derived from crude oil and natural gas production. These assumptions and estimates generally require judgment and include estimates of reserves acquired, liabilities assumed, forecast commodity prices, expected production volumes, future development and operating costs, income taxes, and discount rates. Changes in any of the assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to the net assets acquired, goodwill or gain on business combination.

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.

Accounts Receivable

Significant estimates are included in accounts receivable in terms of collectability as a significant portion of the balance is in dispute, the outcome for which is uncertain and could result in a material adjustment to the financial statements.

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.