Yangarra Resources Ltd.

Management's Discussion and Analysis

For three and nine months ended September 30, 2015

Management's discussion and analysis ("MD&A") of the financial condition and the results of operations should be read in conjunction with the December 31, 2014 audited consolidated financial statements and the September 30, 2015 unaudited consolidated interim financial statements, together with the accompanying notes.

Additional information about Yangarra Resources Ltd. ("Yangarra" or the "Company") 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 November 5, 2015.

The financial information presented herein has been prepared on the basis of International Accounting Standard 34 ("Interim Financial Reporting"). Throughout this discussion, percentage changes are calculated using numbers rounded to the decimal to which they appear. All references to dollar amounts are in Canadian dollars.

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

Non–IFRS and Additional IFRS Measures

This document contains "funds flow from (used in) operations", which is an additional IFRS measure presented in the consolidated financial statements. 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.

<u>Funds flow from operations</u>

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 as presented in the statement of cash flows 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:

	2015	2014	Nine Months Ended	
	Q3	Q3	2015	2014
Cash from operating activities	$ 4,599,582	$ 8,910,365	$ 15,094,643	$ 21,305,219
Changes in non-cash working capital	(433,052)	436,562	2,091,226	6,681,761
Funds flow from operations	$ 4,166,530	$ 9,346,927	$ 17,185,869	$ 27,986,980

Netbacks

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

Net Debt or adjusted working capital (deficit)

Net debt or adjusted working capital (deficit), which represent current assets less current liabilities, excluding current derivative financial instruments, are used to assess efficiency, liquidity and the general financial strength of the Company. There is no IFRS measure that is reasonably comparable to net debt or adjusted working capital (deficit).

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

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

***Forward-looking Statements** – Certain information regarding the Company set forth in this report, including management's assessment of the Company's future plans and operations, contain forward-looking statements that involve substantial known and unknown risks and uncertainties. These risks and uncertainties, many of which are beyond the Company's control, include the impact of general economic conditions and specific industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, the lack of available qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. The Company's actual results, performance or achievements could differ materially from those expressed in, or implied by, these forward-looking statements, and accordingly, no assurance can be given that any events anticipated by the forward-looking statements will transpire or occur, or if any of them do, what benefits the Company can derive from such events.*

Overview

Yangarra is a junior oil and gas company engaged in the exploration, development and production of natural gas and oil with operations in Western Canada, with a main focus on the Cardium in Central Alberta, where the Company has extensive infrastructure and land holdings.

Yangarra is dedicated to creating value for its shareholders through its commitment to a clear business strategy and performance objectives. The Company's strategy is to increase the value of its corporate assets through the drill bit and by assembling a large focused land base in Central Alberta that features high-quality, long-life light oil and liquids-rich gas reserves. The Company has assembled a significant future drilling inventory and will strive to grow this inventory through drilling, geology and strategic acquisitions.

Third Quarter Highlights

- Adjusted EBITDA (which excludes changes in derivative financial instruments) was $4.4 million ($0.07 per share - basic).
- Oil and gas sales, after royalties, were $5.3 million with funds flow from operations of $4.2 million ($0.06 per share - basic). This represents a 64% and a 55% decrease, respectively, from the same period in 2014 due to reductions in commodity pricing and shut in production.
- Production was negatively impacted by rolling TransCanada Pipelines Ltd. ("TCPL") sales line shut downs with daily production averaging 2,158 boe/d for the quarter, a 29% decrease from the same period in 2014 and a 1% increase from the second quarter of 2015.
- Net loss of $2.4 million ($0.03 per share - basic) or $1.8 million before tax ($0.02 per share - basic) including a $5.4 million impairment of exploration & evaluation assets in the North Duvernay block.
- Operating costs were $8.78/boe (including $1.38/boe of transportation costs).
- Operating netbacks, which include the impact of commodity contracts, were $24.79 per boe, a 33% decrease from 2014. Field net backs, which do not include the impact of commodity contracts were $17.97, a decrease of 58% from 2014.
- G&A costs of $1.30/boe.
- Royalties were 2% of oil and gas revenue excluding commodity contracts and 2% of oil and gas revenue including commodity contracts.
- Total capital expenditures were $11.7 million.
- Net debt (which excludes the current derivative financial instruments) was $53.5 million down from $59.8 million at 2014 year end.

Financial Information

	2015 Q3	2014 Q3	Nine Months Ended 2015	Nine Months Ended 2014
Statements of Comprehensive Income				
Petroleum & natural gas sales	$ 5,363,673	$ 14,796,645	$ 18,527,820	$ 44,117,319
Net income (loss) (before tax)	$ (1,782,406)	$ 10,586,337	$ (2,805,495)	$ 15,610,131
Net income (loss)	$ (2,353,636)	$ 7,967,369	$ (4,611,111)	$ 11,538,052
Net income (loss) per share - basic and diluted	$ (0.03)	$ 0.14	$ (0.07)	$ 0.22
Statements of Cash Flow				
Funds flow from operations	$ 4,166,530	$ 9,346,927	$ 17,185,869	$ 27,986,980
Funds flow from (used in) operating activities per share - basic and diluted	$ 0.06	$ 0.16	$ 0.27	$ 0.52
Cash from operating activities	$ 4,599,582	$ 8,910,365	$ 15,094,643	$ 21,305,219
Statements of Financial Position				
Property and equipment	$ 234,947,346	$ 203,295,153	$ 234,947,346	$ 203,295,153
Total assets	$ 261,511,458	$ 224,710,379	$ 261,511,458	$ 224,710,379
Working capital deficit	$ 50,687,278	$ 53,791,373	$ 50,687,278	$ 53,791,373
Adjusted working capital deficit (which excludes current derivative financial instruments)	$ 53,512,533	$ 50,596,689	$ 53,512,533	$ 50,596,689
Non-Current Liabilities	$ 30,494,669	$ 21,164,535	$ 30,494,669	$ 21,164,535
Shareholders equity	$ 160,913,054	$ 134,826,579	$ 160,913,054	$ 134,826,579
Weighted average number of shares - basic	67,681,804	57,746,877	62,555,188	53,512,122
Weighted average number of shares - diluted	67,681,804	60,014,866	62,555,188	53,512,122

Business Environment

	2015 Q3	2014 Q3	Nine Months Ended 2015	Nine Months Ended 2014
Realized Pricing (Including realized commodity contracts)				
Oil ($/bbl)	$ 62.54	$ 83.85	$ 66.49	$ 86.62
NGL ($/bbl)	$ 23.48	$ 50.14	$ 32.86	$ 52.91
Gas ($/mcf)	$ 3.27	$ 4.26	$ 3.31	$ 4.37
Realized Pricing (Excluding commodity contracts)				
Oil ($/bbl)	$ 49.93	$ 90.90	$ 55.06	$ 96.63
NGL ($/bbl)	$ 14.80	$ 55.53	$ 24.74	$ 61.31
Gas ($/mcf)	$ 2.84	$ 4.65	$ 2.94	$ 4.95
Oil Price Benchmarks				
West Texas Intermediate ("WTI") (US$/bbl)	$ 46.45	$ 97.17	$ 51.00	$ 99.61
Edmonton Par (C$/bbl)	$ 52.35	$ 89.50	$ 57.50	$ 92.45
Natural Gas Price Benchmarks				
AECO gas (Cdn$/mcf)	$ 2.90	$ 4.22	$ 2.75	$ 4.55
Foreign Exchange				
U.S./Canadian Dollar Exchange	$ 0.76	$ 0.92	$ 0.79	$ 0.91

Crude oil prices decreased by 52% for the three months ended September 30, 2015, with the West Texas Intermediate ("WTI") reference price averaging US$46.45/bbl compared with US$97.17/bbl in the same period in 2014 due to slowing global economic conditions outside of the U.S. combined with strong growth in North American crude oil supply. Demand for crude oil is generally tied to global economic growth, but is also influenced by factors such as infrastructure, political instability, market uncertainty, weather conditions and government regulations.

Edmonton par differentials to WTI narrowed in the three months ended September 30, 2015 when compared to the same period in 2014, moving from a US$14.83/bbl differential in 2014 to US$6.66/bbl in 2015. In the three months ended September 30, 2015 the US/CDN foreign exchange rate was $0.76 compared to $0.92 for the same period in 2014. The Edmonton par reference price is denominated in Canadian dollars so the change in the foreign exchange rate has increased the Edmonton par price relative to WTI. Edmonton par is the closest reference price point for Yangarra's oil and therefore is the closest proxy to realized pricing.

When compared to 2014, realized pricing on oil decreased by 45%, excluding commodity contracts, and decreased by 25% when the effects of commodity contracts are included. The decrease in oil pricing is a direct result of the decreased WTI pricing.

When compared to 2014, liquids pricing decreased by 73%, excluding commodity contracts, and decreased by 53% when the effects of commodity contracts are included. Pricing for propane and butane were decreased significantly during the second quarter.

During the three months ended September 30, 2015, Yangarra had contracted 300 bbl/day of oil production utilizing WTI fixed price contracts at an average price of C$102.56 per bbl and 500 bbl/d in a costless collar with a floor of C$65.00 WTI/bbl and a ceiling of C$73.50 WTI/bbl. Since the benchmark price was lower than our contracted value the realized prices were positively impacted. As the product is intended to provide protection to both the oil and NGL revenue streams the commodity contracts impact is split between the two products based on their relative production.

AECO natural gas prices decreased for the three months ended September 30, 2015 by 31% to $2.90/mcf from $4.22/mcf in 2014.

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

When compared to 2014, realized pricing on natural gas decreased by 39%, excluding commodity contracts and by 23% when the effects of commodity contracts are included.

Results of Operations

Net petroleum and natural gas production, pricing and revenue

	2015 Q3	2014 Q3	Nine Months Ended 2015	Nine Months Ended 2014
Daily production volumes				
Natural gas (mcf/d)	6,477	9,219	7,711	8,038
Oil (bbl/d)	700	1,004	679	1,014
NGL's (bbl/d)	320	423	307	382
Royalty income				
Natural gas (mcf/d)	232	287	191	315
Oil (bbl/d)	0	9	0	3
NGL's (bbl/d)	19	18	12	23
Combined (boe/d 6:1)	2,158	3,039	2,315	2,814
Revenue				
Petroleum & natural gas sales - Gross	$ 5,363,673	$ 14,546,041	$ 18,527,820	$ 44,117,319
Royalty income	66,770	250,604	181,048	793,859
Commodity contract settlement (1)	1,352,383	(1,216,666)	7,634,614	(5,028,043)
Total sales	6,782,826	13,579,979	26,343,482	39,883,135
Royalty expense	(120,664)	(950,651)	(744,867)	(2,756,123)
Total Revenue - Net of royalties	$ 6,662,162	$ 12,629,328	$ 25,598,615	$ 37,127,012

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

Total sales in the three months ended September 30, 2015 decreased by 50% in 2015 to $6.8 million from $13.6 million in the same period 2014. The decrease is attributable to:

- a 49% decrease in average product prices; and
- a 29% decrease in production (on a boe basis).

Total sales in the nine months ended September 30, 2015 decreased by 34% in 2015 to $26.3 million from $39.9 million in the same period 2014. The decrease is attributable to:

- a 49% decrease in average product prices; and
- an 18% decrease in production (on a boe basis).

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

Company Netbacks ($/boe)

	2015 Q3	2014 Q3	Nine Months Ended 2015	Nine Months Ended 2014
Sales price	$ 27.02	$ 52.80	$ 29.30	$ 57.42
Royalty income	0.34	0.90	0.29	1.03
Royalty expense	(0.61)	(3.40)	(1.18)	(3.59)
Production costs	(7.39)	(6.45)	(7.25)	(6.61)
Transportation costs	(1.38)	(1.52)	(1.45)	(1.57)
Field operating netback	**17.97**	**42.33**	**19.71**	**46.69**
Commodity contract settlement (1)	6.81	(5.13)	12.07	(6.54)
Operating netback	**24.79**	**37.20**	**31.78**	**40.14**
G&A and other (excludes non-cash items)	(1.30)	(2.23)	(1.92)	(1.66)
Finance expenses	(2.59)	(1.42)	(3.16)	(2.47)
Funds flow netback	**20.89**	**33.54**	**26.69**	**36.02**
Depletion and depreciation	(12.85)	(16.72)	(13.49)	(16.56)
E&E Impairment	(27.26)	-	(8.56)	
Accretion	(0.23)	(0.16)	(0.20)	(0.16)
Stock-based compensation	(1.49)	(0.39)	(0.86)	(0.82)
Unrealized gain (loss) on financial instruments	11.95	21.59	(8.03)	1.84
Deferred income tax	(2.88)	(9.37)	(2.86)	(5.30)
Net Income (loss) netback	**$ (11.86)**	**$ 28.49**	**$ (7.29)**	**$ 15.02**

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

The overall average price earned by the Company was lower when compared to the three months ended September 30, 2014 as natural gas prices decreased by 23%, oil prices decreased by 25% and liquid prices decreased by 53%. When compared to the nine months ended September 30, 2014 the natural gas prices decreased by 24%, oil prices decreased by 23% and liquid prices decreased by 38%.

The average sales price decreased by 49% for the three months ended September 30, 2015 and decreased by 49% for the nine months ended September 30, 2015 when compared to the same periods 2014.

Operating netbacks decreased by 33% for the three months ended September 30, 2015 and decreased by 21% for the nine months ended September 30, 2015 when compared to the same period in 2014 with lower realized pricing offset partially by realized hedging gains.

Royalty Income

	2015 Q3	2014 Q3	Nine Months Ended 2015	Nine Months Ended 2014
Royalty income	$ 66,770	$ 250,604	$ 181,048	$ 793,859

Royalty income decreased in 2015 to $66,770 for the three months ended September 30, 2015 and to $181,048 for the nine months ended September 30, 2015 as no new wells have been drilled on the royalty lands, leaving the existing royalty production subject to regular decline rates and reduced commodity prices. The majority of royalty income is a result of the 15% sliding scale royalty purchased in the Willesden Green area in March 2010. There are currently a total of 12 wells generating the 15% royalty income.

Royalty Expense

	2015 Q3	2014 Q3	Nine Months Ended 2015	Nine Months Ended 2014
Royalty expense	$ 120,664	$ 950,651	$ 744,867	$ 2,756,123
Per boe	$ 0.61	$ 3.40	$ 1.18	$ 3.59
As a % of sales (including commodity contracts)	2%	7%	3%	7%
As a % of sales (excluding commodity contracts)	2%	6%	4%	6%

Royalties decreased to $120,664 for the three months ended September 30, 2015 and to $744,867 for the nine months ended September 30, 2015 or 86% and 73% as a percentage of sales, respectively (excluding commodity contract settlements). The decrease is a result of lower production revenues, a lower commodity price environment, as royalty rates are reduced with lower commodity prices, and gas cost allowance rebates.

The royalty per boe decreased for the three and nine month periods ended September 30, 2015 when compared to the same periods in 2014 due to higher commodity pricing in 2014 versus 2015 as royalty rates decrease as commodity prices decrease.

Generally, royalty rates in Western Canada are sensitive to prevailing commodity prices, individual well depth and production rates. The crown royalty rate on the new horizontal wells in Central Alberta is 5% for the earlier of 2 years or 60,000 boe of production. Deep natural gas wells have a royalty rate of 5% for the first 5 years of production.

Production and Transportation Costs

	2015 Q3	2014 Q3	Nine Months Ended 2015	Nine Months Ended 2014
Production costs	$ 1,467,314	$ 1,802,976	$ 4,585,713	$ 5,078,014
Per boe	$ 7.39	$ 6.45	$ 7.25	$ 6.61
Transportation costs	$ 274,708	$ 425,551	$ 915,134	$ 1,203,820
Per boe	$ 1.38	$ 1.52	$ 1.45	$ 1.57
Combined ($/boe)	$ 8.78	$ 7.97	$ 8.70	$ 8.18

Production and transportation costs increased by 10% on a per boe basis when compared to the three months ended September 30, 2014 and increased by 6% when compared to the nine months ended September 30, 2014 due to the lost production from the TCPL shut-downs. The Company's operating costs are largely fixed and as the TCPL shut-downs are only temporary no changes were made to the fixed operating costs in the field. The Company expects production costs (including transportation costs) to move back down to approximately $8.00/boe once the production is restored.

Depletion and depreciation

	2015 Q3	2014 Q3	Nine Months Ended 2015	Nine Months Ended 2014
Depletion and depreciation	$ 2,550,258	$ 4,674,897	$ 8,529,821	$ 12,725,081
Per boe	$ 12.85	$ 16.72	$ 13.49	$ 16.56
Exploration & evaluation asset impairment	$ 5,410,547	$ -	$ 5,410,547	$ -

Depletion and depreciation decreased in the third quarter 2015 compared to the three and nine month periods in 2014 due to decreases in production. On a per boe basis, the depletion decreased when compared to both periods in 2014 due to lower finding and development costs in 2015.

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

General and administrative expenses ("G&A")

	2015 Q3	2014 Q3	Nine Months Ended 2015	Nine Months Ended 2014
Gross G&A expenses	$ 491,947	$ 934,632	$ 1,780,219	$ 2,251,358
G&A recoveries	(233,742)	(310,061)	(563,702)	(978,480)
Net G&A expenses	$ 258,205	$ 624,571	$ 1,216,517	$ 1,272,878
Per boe	$ 1.30	$ 2.23	$ 1.92	$ 1.66

Net G&A decreased by 42% on a boe basis when compared to the three months ended September 30, 2014. The decrease is a result of a reduction of contractors and consultants used as senior office personal are replacing the supervisors on drilling and completion operations. The shift has resulted in reduced costs, improved performance and better efficiency on capital projects. Net G&A increased by 16% on a boe basis when compared to the nine months ended September 30, 2014 due to lower production and reduced overhead recoveries from a reduced drilling program in 2015.

Other expenses

	2015 Q3	2014 Q3	Nine Months Ended 2015	Nine Months Ended 2014
Finance				
Interest Expense	$ 426,516	$ 429,303	$ 1,511,301	$ 1,585,320
Realized losses on interest rate contracts	68,889	-	184,081	-
Change in fair value of interest rate contracts	19,013	(31,240)	305,047	309,218
Accretion	45,112	44,521	127,307	126,686
	$ 559,530	$ 442,584	$ 2,127,736	$ 2,021,224
Stock-based compensation	$ 295,585	$ 108,228	$ 541,092	$ 626,456

Interest and financing fees for the three and nine months ended September 30, 2015 include interest on the revolving operating demand loan (the average amount drawn in 2015 was $56 million), servicing charges on the demand loan and the change in fair value of the interest rate contracts.

The Company had the following interest rate contracts in place at September 30, 2015:

- Pay a 2.35% fixed rate (plus a 2.25% credit spread) on $10 million (October 2015 - June 2018).
- Pay a 2.15% fixed rate (plus a 2.25% credit spread) on $10 million (October 2015 - May 2018).

The fair value on the interest rate contracts was in a loss position of $744,834 as at September 30, 2015 (December 31, 2014 – $439,786).

During the second quarter of 2015, the Company granted options to purchase 2,546,173 common shares, the options will vest equally over three years with the first tranche vesting one year after the grant date. The fair value of the options was estimated at $1,927,215 ($0.76 per option) using the Black-Scholes pricing model. The stock-based compensation expense increased for the three months ended September 30, 2015 when compared to the same period in 2014 due to amortization of un-vested options.

Deferred Taxes

	2015 Q3	2014 Q3	Nine Months Ended 2015	Nine Months Ended 2014
Deferred income tax expense	$ 571,230	$ 2,618,968	$ 1,805,616	$ 4,072,079

Yangarra did not pay income taxes in 2014 and does not expect to pay income taxes in 2015 as is has sufficient tax pools to cover taxable income.

Commodity price risk contracts

	2015 Q3	2014 Q3	Nine Months Ended 2015	Nine Months Ended 2014
Realized (loss) gain on contract settlement	$ 1,352,383	$ (1,216,666)	$ 7,634,614	$ (5,028,043)
Change in fair value of commodity contracts	2,371,579	6,035,816	(5,077,550)	1,410,592
	$ 3,723,962	$ 4,819,150	$ 2,557,064	$ (3,617,451)

As at September 30, 2015, the Company was committed to the following commodity price risk contracts for the sale of oil:

<u>2015 Oil</u>

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

<u>2016 Oil</u>

- 200 bbl/d from January 1 to December 31, 2016 at a fixed price of $76.20 CDN/bbl
- 200 bbl/d from January 1 to December 31, 2016 at a fixed price of $76.00 CDN/bbl

As at September 30, 2015 the Company was committed to the following commodity price risk contracts on the AECO basis:

<u>2015 Gas</u>

- 2,000 GJ/d from October 1 to December 31, 2015 at a fixed price of $4.11/GJ

The fair value of the commodity contracts was $3,416,489 as at September 30, 2015 (December 31 2014 – $8,494,039).

The following table summarizes the sensitivity of the fair value of the Company's derivative positions as at September 30, 2015 to fluctuations in commodity prices, with all other variables held constant. When assessing the potential impact of these commodity price changes, the Company believes 10 percent volatility is a reasonable measure ($0.22/mcf for natural gas and $4.38/bbl for oil). Fluctuations in commodity prices potentially could have resulted in unrealized gains (losses) impacting income before tax as follows:

Sensitivities	Impact on Income Before Tax	
	Increase 10%	Decrease 10%
Crude oil	(1,199,950)	1,199,950
Natural Gas	(40,480)	40,480

Liquidity and Capital Resources

The following table summarizes the change in adjusted working capital (deficit) during the nine months ended September 30, 2015 and the year ended December 31, 2014:

		2015		2014
Adjusted Working capital (deficit) - beginning of period	$	(59,766,933)	$	(36,794,243)
Funds flow from operations		17,185,869		38,325,988
Additions to property and equipment		(24,501,614)		(78,125,708)
Additions to E&E Assets		(4,706,547)		(1,680,941)
Issuance of shares		18,735,453		26,408,338
Issuance (repayment) of Subordinated Debt		-		(7,786,632)
Decommissioning costs incurred		-		(76,361)
Other Debt		(458,761)		(37,374)
Adjusted Working capital (deficit) - end of period	$	(53,512,533)	$	(59,766,933)

Current Credit facility limit	$	80,000,000
Current Subordinated debt facility limit	$	10,000,000

As at September 30, 2015, the $56,489,447 (December 31, 2014 – $55,602,093) reported amount of bank debt with Alberta Treasury Branches ("ATB") was comprised of $6,600,000 (December 31, 2014 – $29,150,000) drawn on the revolving operating demand loan, $49,889,447 (December 31, 2014 – $24,940,715) of guaranteed notes and $nil (December 31, 2014 – $1,511,378) of outstanding cheques. The Company is subject to a financial covenant requiring an adjusted working capital ratio above 1 : 1 (current assets plus the undrawn availability under the revolving facility, divided by the current liabilities less the drawn portion of the revolving facility, excluding unrealized commodity contracts and flow-through share premium liability). The Company was in compliance with this covenant as at September 30, 2015. The facility is secured by a general security agreement.

As at September 30, 2015, the maximum amount available under the revolving operating demand loan was $80,000,000 (December 31, 2014 – $70,000,000) at an interest rate of bank prime plus 1.00% per annum on the operating demand loan, payable monthly, or a credit spread of 2.25% on guaranteed notes. A decrease in the borrowing base could result in a reduction to the credit facility, which may require repayment to the lenders. During the period, the weighted average effective interest rate for the bank debt was approximately 3.7% (2014 – 4.1%).

As at September 30, 2015 the amount available under the subordinated term facility is $10 million. The Company must present a drilling schedule to ATB prior to December 31, 2015 to access the funds and if drawn the funds are repayable on April 17, 2017.

The Company is subject to financial covenants on the subordinated term facility requiring an adjusted working capital ratio greater than 1 : 1 (calculation consistent with the calculation disclosed above) and a Debt to EBITDA ratio below 4 : 1 (Debt is defined as all obligations, liabilities and indebtedness on the statement of financial position less decommissioning liability, deferred income taxes, flow-through share premium liability and commodity\interest contracts and EBITDA is defined as net income plus interest expense and other financing costs, depletion and depreciation and income taxes). In addition the Company is required to comply with a PV-10 proved developed producing ("PDP") to debt ratio of not less than 0.92 : 1 on specified dates and a PV-10 total proved to debt ratio of not less than 1.5 : 1 on specified dates. This facility is secured with a pledge of a general demand debenture and a general security agreement. No amount was outstanding on the subordinated term facility as at September 30, 2015.

The Company intends to fund the 2015 budget with cash flow from operations and the availability on the revolving operating demand loan.

Capital Spending

Capital spending is summarized as follows:

Cash additions	2015 Q3	2014 Q3	Nine Months Ended 2015	Nine Months Ended 2014
Land, acquisitions and lease rentals	$ 223,840	$ 386,844	$ 800,331	$ 2,396,132
Drilling and completion	4,779,372	14,923,634	15,372,738	49,271,094
Geological and geophysical	181,791	458,608	984,260	1,147,492
Equipment	1,795,225	3,829,045	7,151,209	8,210,227
Other asset additions	20,219	(9,272)	193,074	(1,649)
	$ 7,000,447	$ 19,588,859	$ 24,501,612	$ 61,023,296
Exploration & evaluation assets additions	$ 4,706,547	$ -	$ 4,706,547	$ -

During the third quarter, Yangarra drilled the vertical test well in the North Duvernay block (which was subsequently impaired), completed a 1.5 mile well that was drilled in the second quarter, drilled but did not complete a 2-mile well and commenced drilling of a one-mile Ferrier well.

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.

Yangarra was targeting debt to cash flow of 2 to 1 or less for 2015. However due to TCPL outages experienced during the first nine months and continuing into the fourth quarter the Company will not achieve the target. With the shut-in production the ratio was not reflective of the condition of the balance sheet and once the TCPL production resumes the ratio will provide a better indication of the condition of the balance sheet.

Due to the extreme volatility in commodity prices the Company's Board of Directors approved an approach for 2015 that generally matches any capital expenditures to cash flow plus money raises generated by the Company. As a result, no formal budget was approved for 2015.

During the remainder of 2015 Yangarra will drill two 1 mile horizontal wells that will be completed and tied into the Company's Ferrier compression facility in early November. Two additional wells drilled during the second quarter (one 1 mile and one 1.5 mile) are scheduled to be completed in the fourth quarter when crown pipeline right of ways are secured.

Yangarra`s corporate strategy for 2016 in the current commodity environment is to target and maintain 2,500 – 2,750 boe/d while spending within cash-flow at US$45/bbl WTI. Yangarra is preparing for future growth by acquiring significant Cardium acreage at very attractive prices, consolidating partner interests and securing infrastructure. The Company's current inventory supports an ability to increase the pace of development to 2-3 drilling rigs when justified by full cycle returns.

Yangarra intends to complete the standing horizontal well in the South Duvernay Block in the summer of 2016 when processing capacity is expected to be available.

Decommissioning Liabilities

As at September 30, 2015, the undiscounted decommissioning obligation associated with the Company's existing properties was estimated to be $12,928,957 for which $8,996,049 has been recorded using a discount rate of 1.11% - 2.21%, an inflation rate of 2% and an estimated weighted average timing of cash flows of 15 years.

Off Balance Sheet Arrangements

There were no off balance sheet arrangements, other than the office lease commitment and truck lease commitment which is accounted for as an operating lease.

Related Party Transactions

During the three and nine months ended September 30, 2015 and 2014 the Company was charged or invoiced the following amounts by certain of its officers and directors through controlled companies:

	2015 Q3	2014 Q3	Nine Months Ended 2015	Nine Months Ended 2014
Administration and consulting fees	$ 107,502	$ 112,229	$ 260,806	$ 310,229
Production and capital expenditures	19,556	61,047	$ 74,651	89,640
	$ 127,058	$ 173,276	$ 335,457	$ 399,869

Included in accounts payable and accrued liabilities at September 30, 2015 is $48,100 (December 31, 2014 is $6,478) relating to the above transactions. These transactions were in the normal course of operations and were measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. Other long-term liabilities include a mortgage for $262,114 (December 31, 2014 - $291,172) held in the name of an officer of the Company for a property that is used as a field office. The Company is the beneficial owner through a trust agreement of the property against which the mortgage is secured. All mortgage payments are made by the Company.

Share Capital

Details of changes in the number of outstanding equity instruments are detailed in the following table:

	Common Shares	Stock Options
Balance - December 31, 2014	57,755,804	4,113,370
Equity financing	9,926,000	-
Grant of options	-	2,546,173
Forfeited options	-	(84,837)
Expiry of options	-	(446,669)
Balance - September 30, 2015	67,681,804	6,128,037

Contingency

In December 2009, the Company terminated the Standstill Agreement that it had with an industry partner regarding a joint producing property and served that industry partner with a Statement of Claim issued from The Court of Queen's Bench of Alberta, by which the Company claims breach of the agreements between the parties, gross negligence and default of operator. The Company seeks judgment for specified and such further damages to be determined by the Court, as well as appointment as operator. The Company increased the statement of claim based on the information provided by the defendant. The potential outcome of the lawsuit and claims are undetermined, however, they could be material.

In the normal conduct of operations, there are other pending claims by and against the Company. Litigation is subject to many uncertainties, and the outcome of individual matters is not predictable with assurance. In the opinion of management, based on the advice and information provided by its legal counsel, the final determination of these other litigations will not materially affect the Company's financial position or results of operations.

Contractual Obligations and Commitments

As at September 30, 2015	Carrying Amount	Contractual Cash Flows	Less than 1 year	1-2 Years	2-5 Years	More than 5 years
A/P and accrued liabilities	13,001,501	13,001,501	13,001,501	-	-	-
Bank debt (1)	56,489,447	56,489,447	56,489,447	-	-	-
Other long-term liabilities	262,115	262,115	-	59,638	202,477	-
Commodity Contracts	406,743	406,743	406,743	-	-	-
Interest rate contract	744,834	744,834	206,044	274,726	264,064	-
Estimated interest payments (1)	-	1,236,491	1,236,491	-	-	-
Lease agreements for office premises and Company vehicles	–	542,873	60,319	241,277	241,277	
	70,904,640	72,684,004	71,400,545	575,641	707,818	-

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

The Company satisfied its $2,000,790 CDE commitment in the second quarter of 2015. The Company has spent $5,613,990 of the 12,001,300 CEE commitment and the Company has until the end of 2016 to spend the remaining balance.

Financial Instruments and Financial Risk Management

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

The Company is required to classify fair value measurements using a hierarchy that reflects the significance of the inputs used in making the measurements. The fair value hierarchy is as follows:

- Level 1 - quoted prices in active markets for identical assets or liabilities;
- Level 2 - inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly; and
- Level 3 - inputs for the asset or liability that are not based on observable market data.

The fair value of the interest rate contracts and the commodity contracts is classified at level 2. The fair value is calculated using the forward price curves as at September 30, 2015 for the period the contract is outstanding.

The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Company's activities. The Company has exposure to credit risk, liquidity risk and market risk as a result of its use of financial instruments. This note presents information about the Company's exposure to each of the above risks and the Company's objectives, policies and processes for measuring and managing these risks. Further quantitative disclosures are included throughout these financial statements. The Board of Directors has overall responsibility for the establishment and oversight of the Company's risk management framework. The Board has implemented and monitors compliance with the risk management policies as set out herein:

a. Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations. A substantial portion of the Company's accounts receivable are with natural gas and liquids marketers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks.

Purchasers of the Company's natural gas and liquids are subject to credit review to minimize the risk of non-payment. As at September 30, 2015, the maximum credit exposure is the carrying amount of the accounts receivable of $12,682,671 (December 31, 2014 – $13,609,036) and $3,438,042 of commodity contracts (December 31, 2014 – $8,494,039).

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

Oil and natural gas marketers	$	2,566,390
Partners in joint operations		7,190,728
Realized Commodity Contracts		526,140
Other		2,399,413
	$	12,682,671

Receivables from petroleum and natural gas marketers are typically collected on the 25th day of the month following production. The Company's has mitigated the credit risk associated with the oil and natural gas marketer through a security arrangement with Computershare. The Company historically has not experienced any significant collection issues with its petroleum and natural gas marketers. All of the revenue accruals and receivables from petroleum and natural gas marketers were received in October 2015.

Joint venture receivables are typically collected within one to three months of the joint venture bill being issued to the partner. The Company mitigates the risk from joint venture receivables by obtaining partner approval of capital expenditures prior to starting a project. However, the receivables are from participants in the petroleum and natural gas sector, and collection is dependent on typical industry factors such as commodity price fluctuations, escalating costs and the risk of unsuccessful drilling. Further risk exists with joint venture partners as disagreements occasionally arise which increases the potential for non-collection. For properties that are operated by the Company, production can be withheld from joint venture partners who are in default of amounts owing. In addition, the Company often has offsetting amounts payable to joint venture partners from which it can net receivable balances.

The Company did not provide for any doubtful accounts nor was it required to write-off any accounts receivable during the nine months ended September 30, 2015. 54% of the receivables are made up of four industry partners. The company has performed an analysis of each partner's financial situation and have determined they have the ability to pay. In addition the Company has the ability, with each of the partners, to withhold production to collect the outstanding balances

As at September 30, 2015, the Company considers its receivables to be aged as follows:

Under 30 days	$	7,059,549
30 to 60 days		114,100
60 to 90 days		356,373
Over 90 days		5,152,649
	$	12,682,671

b. Liquidity risk

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

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

The Company intends to fund the 2015 budget with cash flow from operations and the availability on the revolving operating demand loan.

c. Market risk

Market risk consists of interest rate risk, currency risk and commodity price risk. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing returns. The Company may use both financial derivatives and physical delivery sales contracts to manage market risks. All such transactions are conducted in accordance with a risk management policy as set out herein:

i. Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate fluctuations on its bank debt which bears interest at a floating rate and to mitigate this risk, the Company has entered into interest rate contracts. For the three months ended September 30, 2015, if interest rates (not including the effect of the interest rate contract) had been 1% lower with all other variables held constant, income for the period would have been $129,715 (September 30, 2014 - $184,035) higher, due to lower interest expense. An equal and opposite impact would have occurred had interest rates been higher by the same amount.

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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 September 30, 2015.

iii. Commodity price risk

Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for petroleum and natural gas are impacted by world economic events that dictate the levels of supply and demand as well as the relationship between the Canadian and United States dollar, as outlined above.

Capital Resources

The Company's objective when managing capital is to maintain a flexible capital structure which will allow it to execute its capital expenditure program, which includes expenditures in oil and gas activities which may or may not be successful. Therefore, the Company monitors the level of risk incurred in its capital expenditures to balance the proportion of debt and equity in its capital structure.

The Company considers its capital structure to include shareholders equity and debt:

	September 30, 2015	*December 31, 2014*
Shareholders' equity	$ 160,913,054	$ 147,838,197
Bank debt	$ 56,489,447	$ 55,602,093

The Company monitors capital based on annual cash from operations before changes in non-cash working capital and capital expenditure budgets, which are updated as necessary and are reviewed and periodically approved by the Board of Directors.

The Company manages its capital structure and makes adjustments by continually monitoring its business conditions including the current economic conditions, the risk characteristics of the Company's petroleum and natural gas assets, the depth of its investment opportunities, current and forecasted net debt levels, current and forecasted commodity prices and other facts that influence commodity prices and funds from operations such as quality and basis differentials, royalties, operating costs and transportation costs.

In order to maintain or adjust the capital structure, the Company considers its forecasted cash from operations before changes in non-cash working capital while attempting to finance an acceptable capital expenditure program including acquisition opportunities, the current level of bank credit available from the Company's lender, the level of bank credit that may be attainable from its lender as a result of petroleum and natural gas reserve growth, the availability of other sources of debt with different characteristics than existing debt, the sale of assets, limiting the size of the capital expenditure program and the issue of new equity if available on favorable terms. At September 30, 2015, the Company's capital structure was subject to the banking covenants disclosed in note 5 of the financial statements. No changes have been made to the capital policy in 2015.

Selected Quarterly Financial Information

	2015 Q3($)	2015 Q2($)	2015 Q1($)	2014 Q4($)
Petroleum & natural gas sales	5,363,673	6,010,973	7,153,174	10,464,894
Net income (loss)	(2,353,636)	(3,202,592)	945,117	12,833,554
Net income per share – basic	(0.03)	(0.05)	0.02	0.22
Net income per share – diluted	(0.03)	(0.05)	0.02	0.22
Funds flow from operations	4,166,530	3,627,985	9,391,354	10,339,008
Funds flow from operations per share – basic	0.06	0.06	0.16	0.18
Funds flow from operations per share –diluted	0.06	0.06	0.16	0.18
Net capital expenditures	11,706,994	8,260,858	9,240,302	18,783,353

	2014 Q3($)	2014 Q2($)	2014 Q1($)	2013 Q4($)
Petroleum & natural gas sales	14,546,041	13,876,299	15,694,979	11,087,956
Net income (loss)	7,967,369	2,851,233	719,450	750,851
Net income (loss) per share – basic	0.14	0.05	0.01	0.03
Net income (loss) per share – diluted	0.13	0.05	0.01	0.03
Funds flow from operations	9,346,927	8,180,361	10,459,692	7,975,588
Funds flow from operations per share – basic	0.16	0.15	0.21	0.18
Funds flow from operations per share –diluted	0.16	0.15	0.21	0.18
Net capital expenditures	19,588,859	19,445,229	21,989,208	23,483,590

Fluctuations in quarterly revenues, net income and funds flow from operations over the last eight quarters are due primarily to the volatility in commodity prices and changes in sales volumes due to production growth and declines tied to the timing of drilling activity. The Company has focused capital expenditures on drilling and completions, with major infrastructure costs for a facility built in 2013. Production has grown steadily, with the exception of 2015 due to due to rolling TCPL sales line shut downs. Revenue has grown steadily over the two year period, with the exception of 2015 and the fourth quarter of 2014 due to a significant drop in commodity pricing.

Business Risks and Uncertainties

The Company is exposed to several operational risks inherent in exploring, developing, producing and marketing crude oil and natural gas. These inherent risks include: economic risk of finding and producing reserves at a reasonable cost; financial risk of marketing reserves at an acceptable price given current market conditions; cost of capital risk associated with securing the needed capital to carry out the Company's operations; risk of environment impact; and credit risk of non-payment for sales contracts and joint venture partners.

The Company attempts to control operating risks by maintaining a disciplined approach to implementation of its exploration and development programs. Exploration risks are managed by hiring experienced technical professionals and by concentrating the exploration activity on specific core regions that have multi-zone potential where the Company has experience and expertise. The Company also generates internal prospects and participates in projects where ownership interest is considered sufficient to minimize risk. Operational control allows the Company to manage costs, timing and sales of production and to ensure new production is brought on-stream in a timely manner. The Company maintains a comprehensive insurance program to reduce risk to an acceptable level and to protect it against significant losses.

Environmental Risks

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Compliance with such legislation can require significant expenditures and a breach could result in the imposition of fines and penalties, some of which could be material. Senior management continually assesses new and existing regulatory requirements and environmental risks and determines the impact these risks might have on the Company, as well as the appropriate actions necessary to manage those risks. These assessments and the resulting policy decisions are discussed quarterly with the Board of Directors which evaluates the performance and effectiveness of the Company's environmental policies and programs.

The Company's environmental responsibilities includes removing property, plant and equipment as well as reclaiming land and property to its original state, subsequent to the completion of oil and natural gas extraction activities. This requirement results in an asset retirement obligation that provides current recognition of estimated expenditures that will be incurred in the future. The Company's decommissioning liabilities are discussed in further detail under "Critical Accounting Estimates" below, as well as in note 6 to the Company's Consolidated Financial Statements.

Disclosure Controls and Procedures and Internal Controls over Financial Reporting

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

The Company has designed internal controls over financial reporting ("ICOFR") to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company is required to disclose herein any change in the Company's internal controls over financial reporting that occurred during the period beginning on July 1, 2015 and ended on September 30, 2015 that has materially affected, or is reasonably likely to materially affect, the Company's ICOFR.

The Company's CEO and CFO now conclude that its DC&P and ICOFR are operating effectively as a result of the changes in ICOFR discussed hereafter

- Due to the relative small number of employees at Yangarra, Management is aware that there is a lack of segregation of duties relating to complex and non-routine financial and tax issues that may arise. To address this potential control weakness. Yangarra has contracted an internal accounting professional for review and advice on complicated financial and tax issues and for tax planning, tax provision and compilation of corporate tax returns.

New Accounting Standards

Future Accounting Policy Changes

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

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

Critical Accounting Estimates

The preparation of the consolidated financial statements in accordance with IFRS requires management to make judgments, estimates and assumptions that affect reported amounts and presentation of assets, liabilities, revenues, expenses and disclosures of contingencies and commitments. Such estimates primarily relate to unsettled transactions and events at the statement of financial position date which are based on information available to management at each financial statement date. Actual results could differ from those estimated. Judgments, estimates and assumptions are continuously evaluated and are based on management's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances.

Critical judgments in applying accounting policies

CGU Determination

The Company's assets are aggregated into cash-generating-units (CGUs) based on their ability to generate largely independent cash flows and are used for impairment testing. CGUs are determined by similar geological structure, shared infrastructure and geographical proximity.

Impairment indicator assessment

The Company assesses its P&E and E&E assets for possible impairment if there are events or changes in circumstances that indicate the carrying values of the assets may not be recoverable. Such indicators include changes in the Company's business plans, changes in commodity prices, evidence of physical damage and significant downward revisions to estimated recoverable volumes or increases in estimated future development expenditures.

Contingencies

By their nature, contingencies will only be resolved when one or more of the future events occur or fail to occur. The assessment of contingencies inherently involves the estimates of the outcome of future events.

Key sources of estimation uncertainty

Reserves

Reserves are used in the unit of production calculation for depletion and depreciation as well as impairment analysis. The quantity of reserves is subject to a number of estimates and projections including assessment of engineering data, projected future rates of production, commodity prices, regulatory changes, operating costs and sustaining capital expenditures. These estimates and projections are uncertain as the Company does not have a long commercial production history to assist in the development of these forward-looking estimates. However, all reserve and associated financial information is evaluated and reported on by a firm of qualified independent reserve evaluators in accordance with the standards prescribed by applicable securities regulators. The calculation of future cash flows based on these reserves is dependent on a number of estimates including: production volumes, facility performance, commodity prices, and royalties, operating costs, sustaining capital and tax rates. The price used in the Company's assessment of future cash flows is based on the Company's independent evaluator's estimate of future prices and evaluated for reasonability by the Company against other available information. The Company believes these prices are reasonable estimates for a long-term outlook.

Decommissioning liabilities

The Company measures decommissioning liabilities at each financial statement date. The estimate is based on the Company's share of costs to reclaim the assets and certain facilities. To determine the future value of the liability, estimates of the amount, timing and inflation of the associated abandonment costs are made. The present value of the cost is recorded as the decommissioning liability using a risk-free discount rate. Due to the long-term nature of current and future project developments, abandonment costs will be incurred many years in the future. As a result of these factors, different estimates could be used for such abandonment costs and the associated timing. Assumptions of higher future abandonment costs, regulatory changes, higher inflation, lower risk-free rates or an assumption of earlier or specified timing of abandonment would cause the decommissioning liability of the corresponding asset to increase. These changes would also cause future accretion expenses to increase and future income to decrease.

Impairment Estimate

The assessment for impairment for P&E and E&E assets involves comparing the carrying value of the CGU with the higher of value in use calculations and fair value less costs to sell. Determination as to whether and how much an asset is impaired involves management estimates on highly uncertain matters such as future commodity prices, the effects of inflation on operating expenses, discount rates, production profiles and the outlook for regional supply-and-demand conditions for crude oil, natural gas and liquids. Impairment is recognized in the statement of income (loss) and comprehensive income (loss) in the period in which carrying amount exceeded the recoverable amount.

Deferred taxes

Deferred income tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amount and the tax basis of assets and liabilities. An estimate is required for both the timing and corresponding tax rate for this reversal. Should these estimates change, it may impact the measurement of the Company's assets or liabilities as well as deferred tax recovery or expense recognized to earnings. Where unfavorable evidence exists, additional considerations and evidence for recognition of deferred tax assets is required. The Company has applied management's judgment and evaluated applicable factors necessary in making this determination and has concluded that the positive evidence in consideration of the estimated future cash flows based on reserve reports from the Company's independent engineers, does not sufficiently outweigh negative factors. The Company only recognizes deferred tax assets arising from unused tax losses to the extent that the Company has sufficient taxable temporary differences or it is probable that sufficient taxable profit will be available against which the unused tax losses can be utilized.

Contingencies

When recognized, management makes its best estimate with respect to future cash outflows.

Other areas of estimates

The recognition of amounts in relation to stock-based compensation requires estimates related to valuation of stock options at the time of issuance including share price, risk free rate, volatility, expected life and dividend yield. The fair value of commodity contracts is calculated using valuation models that require estimates as to future market prices expected interest rates and expected volatility in these variables. By their nature, these estimates are subject to measurement uncertainty and the effect of changes in such estimates on the financial statements for current and future periods could be significant.