Yangarra Resources Ltd.

Management's Discussion and Analysis

For three and nine months ended September 30, 2014

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, 2013 audited consolidated financial statements and the September 30, 2014 unaudited condensed consolidated interim 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 November 12, 2014.

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.

Special Note Regarding Non-IFRS Measures This MD&A contains the terms "funds flow from (used in) operations" and "funds flow from (used in) operations per share", which should not be considered an alternative to or more meaningful than cash from (used in) operating activities as determined in accordance with IFRS. These terms do not have any standardized meaning as prescribed by IFRS. Yangarra's determination of funds flow from (used in) operations and funds flow from (used in) operations per share may not be comparable to that reported by other companies. Management uses funds flow from (used in) operations to analyze operating performance and leverage, and considers funds flow from (used in) 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 (used in) operations is calculated using cash from (used in) operating activities as presented in the statement of cash flows before changes in non-cash working capital. Yangarra presents funds flow from (used in) operations per share whereby per share amounts are calculated using weighted average shares outstanding consistent with the calculation of earnings per share.

The following table reconciles funds flow from (used in) operations to cash from (used in) operating activities, which is the most directly comparable measure calculated in accordance with IFRS:

	2014		2013	Nine Months Ended	
	Q3	Q2	Q3	2014	2013
Cash from operating activities	$ 8,910,365	$ 6,386,075	$ 3,683,552	$ 21,305,219	$ 16,319,945
Changes in non-cash working capital	436,562	1,794,286	2,694,655	6,681,761	1,353,133
Funds flow from operations	$ 9,346,927	$ 8,180,361	$ 6,378,207	$ 27,986,980	$ 17,673,078

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 and 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 working capital (deficit).

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 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

- Production for the quarter was 3,039 boe/d (48% oil and NGL's), a 36% increase from the same period in 2013 and a 17% increase from the previous quarter.
- Oil and gas sales, after royalties, were $13.6 million with funds flow from operations of $9.3 million ($0.16 per share - basic). Both are a 46% increase from the same period in 2013.
- Net Income of $8.0 million ($10.6 million before future income taxes).
- Earnings before interest, taxes, depletion, depreciation and impairment ("EBITDA") was $15.7 million ($0.27 per share - basic), compared with $4.3 million in the same period of 2013. This represents a 265% increase primarily due to positive non-cash changes in the fair value of commodity contracts.
- Operating costs were $6.45 per boe and transportation costs were $1.52 per boe, an increase of 18% and 3%, respectively, from the same period in 2013. Operating costs have been reduced by 7% when compared to the second quarter of 2014.
- Field net backs (operating netback excluding commodity contracts) were $42.33, an increase of 17% from the same period in 2013. Operating netback were $37.20 per boe, an 8% increase from $34.56 per boe reported in the same period of 2013.
- G&A costs were $2.23 per boe, which is a 27% increase from the third quarter of 2013 due to the fees required to graduate to the Toronto Stock Exchange.
- Royalties were 7% of oil and gas revenue (6% when the commodity contracts are excluded).
- Total capital expenditures were $19.6 million. The Company drilled 5 gross (4.2 net) wells.
- Net debt, excluding the current portion of the fair value of commodity contracts, was $51.2 million.
- The annualized third quarter debt to cash flow ratio was 1.4 : 1.
- The Company had utilized 57% of its total debt facility as at September 30, 2014.
- Yangarra has 60% of its 2015 liquids production hedged at an average price of $93.32 CDN/bbl.

Financial Information

	2014 Q3	2014 Q2	2013 Q3	Nine Months Ended 2014	Nine Months Ended 2013
Statements of Comprehensive Income (Loss)					
Petroleum & natural gas sales and royalty income	$ 14,796,645	$ 14,106,137	$ 9,372,931	$ 44,117,319	$ 23,638,701
Net income (loss) for the period (before tax)	$ 10,586,337	$ 3,821,726	$ 39,646	$ 15,610,131	$ 2,569,798
Net income (loss) for the period	$ 7,967,369	$ 2,851,233	$ 11,330	$ 11,538,052	$ 1,834,848
Net income (loss) per share - basic and diluted	$ 0.14	$ 0.05	$ 0.00	$ 0.22	$ 0.05
Statements of Cash Flow					
Funds flow from (used in) operating activities	$ 9,346,927	$ 8,180,361	$ 6,378,207	$ 27,986,980	$ 17,673,078
Funds flow from (used in) operating activities per share - basic and diluted	$ 0.16	$ 0.15	$ 0.16	$ 0.52	$ 0.44
Cash from (used in) operating activities	$ 8,910,365	$ 6,386,075	$ 3,683,552	$ 21,305,219	$ 16,319,945
Statements of Financial Position					
Property and equipment	$ 203,295,153	$ 187,940,259	$ 135,892,343	$ 203,295,153	$ 135,892,343
Total assets	$ 224,710,379	$ 212,513,340	$ 154,773,403	$ 224,710,379	$ 154,773,403
Working Capital (deficit), excluding MTM on commodity contracts	$ 50,596,689	$ 41,022,416	$ 42,594,542	$ 50,596,689	$ 42,594,542
Non-Current Liabilities	$ 21,164,535	$ 19,289,460	$ 13,971,180	$ 21,164,535	$ 13,971,180
Shareholders equity	$ 134,826,579	$ 126,644,146	$ 82,022,213	$ 134,826,579	$ 82,022,213
Weighted average number of shares - basic	57,746,877	53,558,093	40,572,748	53,512,122	40,571,307
Weighted average number of shares diluted	60,014,866	55,898,462	40,662,336	53,512,122	40,571,307

Business Environment

	2014 Q3	2014 Q2	2013 Q3	Nine Months Ended 2014	Nine Months Ended 2013
Realized Pricing (Including commodity contracts)					
Oil ($/bbl)	$ 83.85	$ 86.91	$ 96.51	$ 86.62	$ 95.00
NGL ($/bbl)	$ 50.14	$ 46.12	$ 53.33	$ 52.91	$ 55.50
Gas ($/mcf)	$ 4.26	$ 3.87	$ 3.05	$ 4.37	$ 3.35
Realized Pricing (Excluding commodity contracts)					
Oil ($/bbl)	$ 90.90	$ 100.16	$ 102.99	$ 96.63	$ 93.59
NGL ($/bbl)	$ 55.53	$ 59.38	$ 60.77	$ 61.31	$ 53.69
Gas ($/mcf)	$ 4.65	$ 4.55	$ 2.57	$ 4.95	$ 3.07
Oil Price Benchmarks					
West Texas Intermediate ("WTI") (US$/bbl)	$ 97.17	$ 103.00	$ 105.81	$ 99.61	$ 98.20
Edmonton (C$/bbl)	$ 89.50	$ 97.10	$ 103.65	$ 92.45	$ 94.83
Natural Gas Price Benchmarks					
AECO gas (Cdn$/GJ)	$ 4.22	$ 4.65	$ 2.82	$ 4.55	$ 3.16
Foreign Exchange					
U.S./Canadian Dollar Exchange	$ 0.918	$ 0.920	$ 0.963	$ 0.914	$ 0.977

Crude oil prices weakened in the three months ended September 30, 2014, with the West Texas Intermediate ("WTI") reference price averaging US$97.17/bbl compared with US$105.81 per barrel the same period in 2013 and US$103.00/bbl in the second quarter of 2014. 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 widened in the three months ended September 30, 2014 when compared to the same period in 2013, moving from a $2.16/bbl differential in 2013 to $7.67/bbl in 2014. The closest reference price point for Yangarra's oil is Edmonton par and therefore movements in the differential have a significant impact on the Company realized pricing.

When compared to the same period in 2013 realized pricing on oil decreased by 12%, excluding commodity contracts, and decreased by 13% 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 the same period in 2013 liquids pricing decreased by 9%, excluding commodity contracts, and decreased by 6% when the effects of commodity contracts are included. Significant reductions in propane prices and condensate prices (which are generally linked to WTI pricing) were the largest factor in the lower liquids prices.

During the three months ended September 30, 2014, Yangarra had contracted 1,200 bbl/day of oil production utilizing WTI fixed price contracts at an average price of $95.20 per bbl. Since the benchmark price was higher than our contracted value the realized prices were negatively 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 increased for the three months ended September 30, 2014 by 50% to $4.65/GJ from $2.82/GJ the same period in 2013.

Yangarra has contracted 5,000 GJ/day of 2014 natural gas production utilizing AECO fixed price contracts at an average price of $3.39 per GJ. AECO pricing decreased by 9% when compared to the second quarter of 2014.

When compared to the same period in 2013 realized pricing on natural gas increased by 81%, excluding commodity contracts and by 39% when the effects of commodity contracts are included.

Results of Operations

Net petroleum and natural gas production, pricing and revenue

	2014		2013	Nine Months Ended	
	Q3	Q2	Q3	2014	2013
Daily production volumes					
Natural gas (mcf/d)	9,219	7,306	6,983	8,038	6,003
Oil (bbl/d)	1,004	1,003	547	1,014	513
NGL's (bbl/d)	423	309	450	382	361
Royalty income					
Natural gas (mcf/d)	287	302	299	315	609
Oil (bbl/d)	9	1	1	3	1
NGL's (bbl/d)	18	26	26	23	41
Combined (boe/d 6:1)	3,039	2,606	2,238	2,814	2,018
Revenue					
Petroleum & natural gas sales - Gross	$ 14,546,041	$ 13,876,299	$ 9,372,931	$ 44,117,319	$ 23,638,701
Royalty income	250,604	229,838	195,468	793,859	931,415
Commodity contract settlement	(1,216,666)	(2,088,038)	(326,435)	(5,028,043)	909,693
Total sales	13,579,979	12,018,099	9,241,964	39,883,135	25,479,809
Royalty expense	(950,651)	(867,916)	(701,597)	(2,756,123)	(1,239,554)
Petroleum & natural gas sales - Net	12,629,328	11,150,183	8,540,367	37,127,012	24,240,255
Change in fair value of contracts	6,035,816	(222,122)	(2,411,102)	1,410,592	(4,711,321)
Total Revenue - Net of royalties	$ 18,665,144	$ 10,928,061	$ 6,129,265	$ 38,537,604	$ 19,528,934

Total sales in Q3 2014 were $13.6 million compared to $9.2 million in the same period 2013. The increase in sales is attributable to:

- a 36 % increase in production (on a boe basis); offset by
- a 16% decrease in average product prices.

When compared to the $12.0 million of total sales in the second quarter of 2014, the increased sales are attributable to:

- a 10% decrease in average product prices; offset by
- a 17% increase in production (on a boe basis).

The increase in production is from bringing on-stream 8 gross (4.6 net) wells in the third quarter of 2014.

Company Netbacks ($/boe)

	2014 Q3	2014 Q2	2013 Q3	Nine Months Ended 2014	Nine Months Ended 2013
Sales Price	$ 52.80	$ 58.53	$ 45.53	$ 57.42	$ 42.91
Royalty income	0.90	0.97	0.95	1.03	1.69
Royalty expense	(3.40)	(3.66)	(3.41)	(3.59)	(2.25)
Production costs	(6.45)	(6.92)	(5.45)	(6.61)	(6.35)
Transportation costs	(1.52)	(1.88)	(1.47)	(1.57)	(1.26)
Field operating netback	**42.33**	**47.04**	**36.15**	**46.69**	**34.74**
Commodity contract settlement	(5.13)	(8.81)	(1.59)	(6.54)	1.65
Operating netback	**37.20**	**38.23**	**34.56**	**40.14**	**36.39**
G&A and other (excludes non-cash items)	(2.23)	(1.36)	(1.76)	(1.66)	(2.05)
Finance expenses	(1.42)	(2.78)	(2.32)	(2.47)	(2.19)
Cash flow netback	**33.54**	**34.10**	**30.49**	**36.02**	**32.15**
Depletion and depreciation	(16.72)	(16.41)	(18.05)	(16.56)	(18.21)
Accretion	(0.16)	(0.17)	(0.15)	(0.16)	(0.20)
Stock-based compensation	(0.39)	(0.46)	(0.38)	(0.82)	(0.53)
Unrealized gain (loss) on financial instruments	21.59	(0.94)	(11.71)	1.84	(8.55)
Deferred income tax	(9.37)	(4.09)	(0.14)	(5.30)	(1.33)
Net Income netback	**$ 28.49**	**$ 12.03**	**$ 0.06**	**$ 15.02**	**$ 3.33**

The overall average price earned by the Company was higher when compared to 2013 as natural gas prices increased by 81% and oil prices decreased by 12%. The net affect was positive to pricing as the Company has a 52% gas weighting. The average sales price increased by 34% for the nine months ended September 30, 2014 when compared to the same period in 2013.

Operating netbacks increased by 8% when compared to the same period in 2013 and decreased by 3% when compared to the second quarter of 2014 due to the impact the commodity prices changes and the settlement of commodity contracts. Operating net backs for the nine months ended September 30, 2014 were up 10% when compared to the same period in 2013 as the sales price increases were largely offset by commodity contract changes.

Royalty Income

	2014 Q3	2014 Q2	2013 Q3	Nine Months Ended 2014	Nine Months Ended 2013
Royalty Income	$ 250,604	$ 229,838	$ 195,468	$ 793,859	$ 931,415

Royalty income increased in 2014 to $250,604 when compared to the same period in 2013 due to a one-time, one well, additional over-riding royalty added by the Company during the quarter. Royalty income for the nine months ended September 30, 2014 was $793,859, down 15% from the same period in 2013 due to the natural declines of the wells subject to the 15% sliding scale royalty.

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

	2014		2013	Nine Months Ended	
	Q3	Q2	Q3	2014	2013
Royalty Expense	$ 950,651	$ 867,916	$ 701,597	$ 2,756,123	$ 1,239,554
Per boe	$ 3.40	$ 3.66	$ 3.41	$ 3.59	$ 2.25
As a % of sales (including commodity contracts)	7%	7%	8%	7%	5%
As a % of sales (excluding commodity contracts)	6%	6%	7%	6%	5%

Royalties increased to $950,651 for the three months ended September 30, 2014 or 6% as a percentage of sales (excluding commodity contact settlements). The increase is a result of higher production volumes during the quarter as the percentage of sales remained constant. Royalties increased to $2,756,123 for the nine months ended September 30, 2014 due to increased volumes.

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

	2014		2013	Nine Months Ended	
	Q3	Q2	Q3	2014	2013
Production costs	$ 1,802,976	$ 1,641,107	$ 1,122,452	$ 5,078,014	$ 3,497,260
Per boe	$ 6.45	$ 6.92	$ 5.45	$ 6.61	$ 6.35
Transportation costs	$ 425,551	$ 445,058	$ 302,408	$ 1,203,820	$ 692,521
Per boe	$ 1.52	$ 1.88	$ 1.47	$ 1.57	$ 1.26
Combined ($/boe)	$ 7.97	$ 8.80	$ 6.92	$ 8.18	$ 7.61

Production costs increased in 2014 to $1.8 million on a dollar basis is due to additional production and increased by 15% on a per boe basis when compared to the same period in 2013. The change is due to the timing of fixed costs that increase with production, but typically lag behind the actual production increases. The Company expects $8.00/boe (operating and transportation) when averaged out over longer periods of time. When compared to the second quarter of 2014 the production costs on a per boe basis decreased as the production shut-in in the second quarter was turned back on.

On a per boe basis, transportation costs have stayed relatively consistent when compared to the same period in 2013 as the trucking costs reflected the liquids content of 48% in the third quarter which was consistent with 2013.

Production and transportation costs for the nine months ended September 30, 2014 increased due to additional production volumes, on a per boe basis costs increased slightly due fee increases for transportation and industry-wide cost pressures due to higher activity levels.

Depletion, depreciation, impairment and accretion

	2014 Q3	2014 Q2	2013 Q3	Nine Months Ended 2014	Nine Months Ended 2013
Depletion and depreciation	$ 4,674,897	$ 3,890,898	$ 3,715,664	$ 12,725,081	$ 10,033,740
Per boe	$ 16.72	$ 16.41	$ 18.05	$ 16.56	$ 18.21
Accretion	$ 44,521	$ 41,099	$ 30,977	$ 126,686	$ 108,506

Depletion and depreciation increased for the three and nine months ended September 30, 2014 when compared to the same periods 2013 due to increases in production. On a per boe basis depletion and depreciation decreased as the capital program resulted in additions to the reserve base.

General and administrative expenses ("G&A")

	2014 Q3	2014 Q2	2013 Q3	Nine Months Ended 2014	Nine Months Ended 2013
Gross G&A expenses	$ 934,632	$ 717,123	$ 459,801	$ 2,251,358	$ 1,703,535
G&A recoveries	(310,061)	(395,495)	(97,988)	(978,480)	(571,403)
Net G&A expenses	$ 624,571	$ 321,628	$ 361,813	$ 1,272,878	$ 1,132,132
Per boe	$ 2.23	$ 1.36	$ 1.76	$ 1.66	$ 2.05

During the three and nine months ended September 30, 2014, general and administrative expenses increased on a net basis when compared to the same periods in 2013 due increased volumes and a one-time expense related to the Company's graduation to the Toronto Stock Exchange.

Other expenses

	2014 Q3	2014 Q2	2013 Q3	Nine Months Ended 2014	Nine Months Ended 2013
Finance					
Interest (includes released losses on interst rate contracts)	$ 429,303	$ 562,029	$ 375,487	$ 1,585,320	$ 1,245,264
Change in fair value of interest rate contracts	(31,240)	96,288	101,618	309,218	(39,887)
Accretion	44,521	41,099	$ 30,977	126,686	$ 108,506
	$ 442,584	$ 699,416	$ 508,082	$ 2,021,224	$ 1,313,883
Stock-based compensation	$ 108,228	$ 108,228	$ 79,200	$ 626,456	$ 289,600

Interest and financing fees for the three months ended September 30, 2014 include interest on the revolving operating demand loan (the average amount drawn in 2014 was $47 million), the subordinated term facility and the change in fair value of the interest rate contracts.

The Company had the following interest rate contracts in place at September 30, 2014:

- Pay a floating rate to receive a 2.35% (plus a 2.50% credit spread) fixed rate on $10 million (October 2014-June 2018)

- Pay a floating rate to receive a 2.15% (plus a 2.50% credit spread) fixed rate on $10 million (October 2014-May 2018)

The fair value on the interest rate contracts was in a loss position of ($352,454) as at September 30, 2014 (December 31, 2013 – $43,236).

During the nine months ended September 30, 2014, the Company granted options to purchase 1,291,677 common shares, (400,002 of the options vested immediately and 891,675 of 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 $1,683,600 ($1.32 per option) using the Black-Scholes pricing model.

Deferred Taxes

	2014		2013	Nine Months Ended	
	Q3	Q2	Q3	2014	2013
Deferred income tax expense	$ 2,618,968	$ 970,493	$ 28,316	$ 4,072,079	$ 734,950

The Company's effective tax rate for 2014 was 25%, however, Yangarra did not pay income taxes in 2014 and does not expect to pay income taxes in 2015 as it has sufficient tax pools to cover taxable income.

Commodity price risk contracts

	2014		2013	Nine Months Ended	
	Q3	Q2	Q3	2014	2013
Realized (loss) gain on contract settlement	$ (1,216,666)	$ (2,088,038)	$ (326,435)	$ (5,028,043)	$ 909,693
Change in fair value of commodity contracts	6,035,816	(222,122)	(2,411,102)	1,410,592	(4,711,321)
	$ 4,819,150	$ (2,310,160)	$ (2,737,537)	$ (3,617,451)	$ (3,801,628)

As at September 30, 2014, the Company was committed to the following commodity price risk contracts for the sale of oil:

2014 Oil

100 bbl/d from October 1 to December 31, 2014 at a fixed price of $98.30 CAD/bbl
100 bbl/d from October 1 to December 31, 2014 at a fixed price of $100.00 CAD/bbl
100 bbl/d from October 1 to December 31, 2014 at a fixed price of $91.40 CAD/bbl
100 bbl/d from October 1 to December 31, 2014 at a fixed price of $91.35 CAD/bbl
200 bbl/d from October 1 to December 31, 2014 at a fixed price of $92.00 USD/bbl
100 bbl/d from October 1 to December 31, 2014 at a fixed price of $90.00 USD/bbl
200 bbl/d from October 1 to December 31, 2014 at a fixed price of $93.52 CAD/bbl
100 bbl/d from October 1 to December 31, 2014 at a fixed price of $98.20 CAD/bbl
200 bbl/d from October 1 to December 31, 2014 at a fixed price of $100.00 CAD/bbl

2015 Oil

100 bbl/d from January 1 to December 31, 2015 at a fixed price of $86.05 USD/bbl
100 bbl/d from January 1 to December 31, 2015 at a fixed price of $91.20 CDN/bbl
200 bbl/d from January 1 to December 31, 2015 at a fixed price of $90.37 CDN/bbl
100 bbl/d from January 1 to December 31, 2015 at a fixed price of $90.10 CDN/bbl
100 bbl/d from January 1 to December 31, 2015 at a fixed price of $92.25 CDN/bbl
200 bbl/d from January 1 to December 31, 2015 at a fixed price of $92.45 CDN/bbl
200 bbl/d from January 1 to December 31, 2015 at a fixed price of $100.00 CDN/bbl

2016 Oil

Sold Swaption on 200 bbl/d @ $95.00 WTI/USD for January – December 2016

2014 Propane

100 bbl/d from April 1 to September 30, 2014 at a fixed price of $45.99 CDN/bbl

As at September 30, 2014 the Company was committed to the following commodity price risk contracts on the AECO basis:

2014 Gas

1,000 GJ/d from October 1 to December 31, 2014 at a fixed price of $3.11/GJ
1,000 GJ/d from October 1 to December 31, 2014 at a fixed price of $3.05/GJ
1,000 GJ/d from October 1 to December 31, 2014 at a fixed price of $3.54/GJ
1,000 GJ/d from October 1 to December 31, 2014 at a fixed price of $3.54/GJ
1,000 GJ/d from October 1 to December 31, 2014 at a fixed price of $3.73/GJ

2015 Gas

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

The fair value of the commodity contracts was in a loss position of ($3,119,904) as at September 30, 2014 (December 31, 2013 – $4,530,496).

The following table summarizes the sensitivity of the fair value of the Company's derivative positions as at September 30, 2014 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 ($0.44/mcf for natural gas and $11/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	(5,308,520)	5,308,520
Natural Gas	(325,805)	325,805

Liquidity and Capital Resources

The following table summarizes the change in working capital during the nine months ended September 30, 2014 and the year ended December 31, 2013:

		2014		2013
Working capital (deficit) - beginning of period (1)	$	(36,794,243)	$	(36,301,842)
Funds flow from operating activities		27,986,980		25,648,666
Additions to property and equipment & E&E Assets		(61,023,296)		(47,485,106)
Issuance of shares		26,408,338		13,593,273
Issuance of Subordinated Debt		(7,786,632)		7,786,632
Other Debt		(27,886)		(35,866)
Working capital (deficit) - end of period (1)	$	(51,236,739)	$	(36,794,243)
Subordinated Debt Outstanding	$	-	$	(7,786,632)
Total Debt	$	(51,236,739)	$	(44,580,875)
Credit facility limit	$	70,000,000	$	45,000,000
Subordinated debt facility limit	$	20,000,000	$	20,000,000

(1) Excludes current portion of fair value of commodity contracts

As at September 30, 2014, the $50,629,602 (December 31, 2013 – $32,112,455) reported amount of bank debt with Alberta Treasury Branches ("ATB") was comprised of $17,750,000 (December 31, 2013 – $9,850,000) drawn on the revolving operating demand loan, $24,955,561 (December 31, 2013 – $19,963,177) of guaranteed notes and $7,924,041 (December 31, 2013 – $2,299,280) 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 facility is secured by a general security agreement.

As at September 30, 2014, the maximum amount available under the revolving operating demand loan was $70,000,000 (December 31, 2013 – $45,000,000) at an interest rate of bank prime plus 0.75% per annum on the operating demand loan, payable monthly, or a credit spread of 2.0% on guaranteed notes. The next scheduled review is May 31, 2015. 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 4.4% (2013 – 4.9%).

As at September 30, 2014 nil was drawn on the $20,000,000 subordinated term loan facility with Alberta Treasury Branches ("ATB"). The subordinated term loan has a two year committed term (subject to an extension for an additional year upon mutual consent). There are two tranches ($9,000,000 to be drawn on or before October 1, 2014 and $11,000,000 to be drawn on or before January 1, 2015) at an interest rate of bank prime plus 7.0% per annum, payable monthly, or a credit spread of 8.0% on guaranteed notes. Full payment of the principal is due on September 3, 2015. The first tranche was not drawn on the October 1, 2014, reducing the current availability of the subordinated term loan facility to $10,000,000.

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 balance sheet and EBITDA is defined as earnings 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.

The Company is in compliance with all covenants as at September 30, 2014.

The annualized third quarter cash flow ratio as at September 30, 2014 was 1.4 : 1 (excluding the current portion of the fair value of commodity contracts).

Yangarra intends to fund the 2014 budget (which includes the $4.5 million of CEE commitments) with cash flow from operations and the availability on the revolving operating demand loan.

Capital Spending

Capital spending is summarized as follows:

	2014		2013	Nine Months Ended	
Cash Additions	Q3	Q2	Q3	2014	2013
Land, acquisitions and lease rentals	$ 386,844	$ 1,037,155	$ 307,274	$ 2,396,132	$ 1,140,889
Drilling and completion	14,923,634	15,973,721	6,725,516	49,271,094	15,952,432
Geological and geophysical	458,608	368,657	417,101	1,147,492	586,305
Equipment	3,829,045	2,056,234	1,036,654	8,210,227	5,641,331
Other Asset Additions	(9,272)	9,462	80,681	(1,649)	217,461
	$ 19,588,859	$ 19,445,229	$ 8,567,226	$ 61,023,296	$ 23,538,418
Exploration & evaluation assets additions	$ -	$ -	$ -	$ -	$ -

The Company drilled 5 gross (4.2 net) wells and completed and brought on-stream 8 gross (4.6 net) wells during the third quarter. Production during the quarter continued to be negatively affected by third party restrictions as well as the below type curve results from a two well Glauc oil pad.

Outlook

The Company drilled 5 gross (4.2 net) wells and completed and brought on-stream 8 gross (4.6 net) wells during the third quarter. Production during the quarter continued to be negatively affected by third party restrictions as well as the below type curve results from a two well Glauc oil pad. No mechanical issues were experienced in the Glauc oil wells; however, the frac fluids appear to be impeding inflow with production slowly improving over time.

In Q4, third party restrictions have mostly been alleviated as of November 1st, and Yangarra plans to bring on-stream 4 gross (2.4 net) wells drilled and completed in the previous quarter. Subsequent to quarter end, Yangarra plans to drill, complete and bring on-stream 6 gross (3.6 net) wells.

A Duvernay well was spud in Willesden Green October 2, 2014 and is drilling according to program with an estimated cost of $6.0 million. Yangarra will provide an update upon on the well and Duvernay strategy once the well is drilled and rig released.

The Company has revised the fourth quarter pricing to an average price of US$80.00/bbl for WTI crude oil (CDN$79.20/bbl Edmonton par) and an average price of $3.50/GJ for AECO natural gas. With the reduced pricing and third party constraints the Company now expects fourth quarter cash flow of $12 million and full year cash flow of $40 million (a 56% increase from 2013).

Fourth quarter production is expected to be 3,500 boe/d and full year production is expected to average 3,000 boe/d (a 36% increase from 2013).

The Company has $14 million remaining to spend on its $75 million 2014 capital budget in the fourth quarter and expects year-end 2014 debt of $53 million resulting in a net debt to annualized fourth quarter cash flow ratio of 1.1 to 1.0.

Decommissioning Liabilities

As at September 30, 2014, the undiscounted decommissioning obligation associated with the Company's existing properties was estimated to be $11,239,694 for which $7,387,419 has been recorded using a discount rate of 1.83% - 2.96%, 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 and truck lease commitment which is accounted for as an operating lease.

Related Party Transactions

During the three and nine months ended September 30, 2014 and 2013 the Company was charged or invoiced the following amounts by certain of its officers and directors through controlled companies:

	2014		2013	Nine Months Ended	
	Q3	Q2	Q3	2014	2013
Administration and consulting fees	$ 112,229	$ 99,000	$ 88,500	$ 310,229	$ 222,035
Production and capital expenditures	61,047	33,043	52,033	$ 89,640	175,952
	$ 173,276	$ 132,043	$ 140,533	$ 399,869	$ 397,987

Included in accounts payable and accrued liabilities at September 30, 2014 is $6,849 (December 31, 2013 – $7,727) 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 $300,660 (December 31, 2013 - $328,545) 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	Warrants	Stock Options
Balance - December 31, 2013	49,039,002	473,335	3,545,031
Equity Financing	8,333,417	-	-
Grant of options	-	-	1,291,677
Exercise of options	383,335	-	(383,336)
Share Consolidation	50	-	-
Balance - September 30, 2014	57,755,804	473,335	4,453,372
Grant of Options	-	-	-
Exercise of options	-	-	-
Balance - Date of MD&A	57,755,804	473,335	4,453,372

In May 2014, the Company consolidated its outstanding common shares, stock options and warrants on a 1 for 3 basis (the "Share Consolidation"). As a result, the number of outstanding common shares, stock options and warrants of comparative periods have been reduced by a factor of three, in order for the comparative common share, stock options, warrants, per share amounts and diluted per share amounts to be equivalent.

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

Commitments

The Company has until December 31, 2014 to incur $4.5 million of qualifying CEE flow-through expenditures related to CEE flow-through shares issued in December 2013.

The Company has entered into lease agreements for office premises, field equipment and Company vehicles with estimated minimum annual payments as follows:

2014	$	60,319
2015	$	241,277
2016	$	241,277

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 as level 2. The fair value is calculated using the forward price curves as at September 30, 2014.

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. 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, 2014, the maximum credit exposure is the carrying amount of the accounts receivable of $13,235,696 (December 31, 2013 – $8,846,547).

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

Oil and natural gas marketers	$	5,327,500
Joint venture partners		5,445,998
Other		2,462,198
	$	13,235,696

Receivables from petroleum and natural gas marketers are typically collected on the 25th day of the month following production. The Company's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large purchasers. 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 2014.

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 three months ended September 30, 2014.

As at September 30, 2014, the Company considers its receivables to be aged as follows:

Not past due	$	8,183,097
Past due by less than 90 days		70,565
Past due by more than 90 days		4,982,034
	$	13,235,696

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 balance based on their maturity dates.

Yangarra intends to fund the 2014 budget (which includes the $4.5 million of CEE commitments) 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, 2014, if interest rates had been 1% lower with all other variables held constant, income for the period would have been $323,777 (September 30, 2013 - $265,585) 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 September 30, 2014.

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, 2014*	*December 31, 2013*
Shareholders' equity	$ **134,826,579**	$ 95,583,587
Bank debt	$ **50,629,602**	$ 32,112,455
Subordinated debt	$ –	$ 7,786,632

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, 2014, the Company's capital structure was not subject to external restrictions. No changes have been made to the capital policy since 2013.

Selected Historical Financial Information

	2014 Q3($)	2014 Q2($)	2014 Q1($)	2013 Q4($)
Petroleum & natural gas sales and royalty income	**14,796,645**	14,106,137	16,008,396	11,265,291
Net petroleum and natural gas revenue	**13,845,994**	13,238,221	15,070,840	10,708,013
Net income (loss)	**7,967,369**	2,851,233	719,450	750,851
Net income (loss) per share – basic	**0.14**	0.05	0.03	0.03
Net income (loss) per share – diluted	**0.13**	0.05	0.03	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	22,920,532

	2013 Q3($)	2013 Q2($)	2013 Q1($)	2012 Q4($)
Petroleum & natural gas sales and royalty income	9,568,399	8,113,998	6,887,719	5,059,036
Net petroleum and natural gas revenue	8,866,802	7,837,133	6,626,627	5,055,666
Net income (loss)	11,330	2,082,942	(259,424)	340,623
Net income (loss) per share – basic	0.00	0.06	0.00	0.00
Net income (loss) per share – diluted	0.00	0.06	0.00	0.00
Funds flow from operations	6,378,207	6,480,689	4,814,183	3,168,328
Funds flow from operations per share – basic	0.16	0.15	0.16	0.09
Funds flow from operations per share –diluted	0.16	0.15	0.16	0.09
Net capital expenditures	8,567,226	3,708,601	11,262,592	4,537,364

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 through successful drilling activity.

Business Risks and Uncertainties

Refer to the December 31, 2013 MD&A for a complete listing of Business Risks and Uncertainties.

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.

Internal Controls over Financial Reporting

Internal control over financial reporting is a process designed to provide reasonable assurance that all the assets are safeguarded and transactions are appropriately authorized, and to facilitate the preparation of relevant, reliable and timely information.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Yangarra is required to comply with National Instrument 52-109 – "Certification of Disclosure in Issuers' Annual and Interim Filings" and management has assessed the effectiveness of the Company's internal control over financial reporting as defined by this instrument. The assessment was based on the framework in Internal Control – Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

The certification of interim filings for interim period ended September 30, 2014 requires that Yangarra disclose in the interim MD&A any weaknesses in the Company's internal control over financial reporting that occurred during the period that have materially affected, or are reasonably likely to materially affect, Yangarra's internal control over financial reporting.

During the design assessment certain material weaknesses in internal controls over financial reporting were identified, as follows:

- 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. It is not deemed as economically feasible at this time to have such personnel. Yangarra relies on external experts for review and advice on complicated financial and tax issues and for tax planning, tax provision and compilation of corporate tax returns.

These weaknesses in internal controls over financial reporting result in a more than remote likelihood that a material misstatement would not be prevented or detected. Management and the Board of Directors work to mitigate the risk of material misstatement, however, management and the Board of Directors do not have reasonable assurance that this risk can be reduced to a remote likelihood of a material misstatement.

New Accounting Standards

On January 1, 2014 the Company adopted the following new standards:

The IASB issued International Financial Reporting Interpretations Committee Interpretation ("IFRIC") 21, "Levies". The IFRIC clarifies that an entity should recognize a liability for a levy when the activity that triggers payment occurs. The adoption of this interpretation had no significant impact on the Company's consolidated financial statements.

IAS 32, "Financial Instruments: Presentation", which clarifies the requirements for offsetting financial assets and liabilities. The amendments clarify when an entity has a legally enforceable right to offset and certain other requirements that are necessary to present a net financial asset or liability. There was no impact to the Company on adoption of this standard.

Critical Accounting Estimates

Refer to the December 31, 2013 MD&A for a complete listing of critical accounting estimates.