

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") of the financial condition and results of operations of Parex Resources Inc. ("Parex" or the "Company") for the three months and years ended December 31, 2014 and 2013 is dated March 10, 2015 and should be read in conjunction with the audited consolidated financial statements for the years ended December 31, 2014 and 2013. The audited consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS" or "GAAP") as issued by the International Accounting Standards Board.

Additional information related to Parex and factors that could affect the Company's operations and financial results are included in reports on file with Canadian securities regulatory authorities, including the Company's Annual Information Form dated March 19, 2014, and may be accessed through the SEDAR website at www.sedar.com.

All financial amounts are in United States (US) dollars unless otherwise stated.

Company Profile

Parex is an oil and gas company actively engaged in crude oil exploration, development and production in Colombia. Headquartered in Calgary, Canada, Parex, through its foreign subsidiaries, holds interests in onshore exploration and production blocks totaling approximately 2,616,897 gross acres. The common shares of the Company trade on the Toronto Stock Exchange ("TSX") under the symbol PXT.

Abbreviations

Refer to the end of the MD&A for commonly used abbreviations in the document. Refer to page 24 for the Advisory on Forward-Looking Statements and page 26 for Non-GAAP Terms used.

2014 Highlights

- Achieved annual average oil production in 2014 of 22,526 barrels per day, an increase of 42 percent over 2013;
- Released an updated independently evaluated reserves assessment prepared by GLJ Petroleum Consultants Ltd with proved plus probable reserves growth of 114 percent over 2013, increasing to 68.4 million barrels of oil equivalent at December 31, 2014 from 32.0 million barrels of oil equivalent (net company working interest) at December 31, 2013;
- Finding, Development and Acquisition costs ("FD&A") for the year were \$18.90/boe for proved reserves and \$13.79/boe for proved plus probable reserves including future development capital;
- Improved net debt to \$31.7 million at December 31, 2014 compared to \$70.2 million at December 31, 2013 ;
- Generated year end funds flow from continuing operations of \$293.9 million (\$2.44 per share basic). Funds flow has increased from the prior year due to production growth from exploration and appraisal success;
- Recorded a net loss of \$108.8 million for the year ended December 31, 2014. The net loss was driven by non-cash impairment charges mainly associated with the decrease in world oil prices. Adjusted net income (adjusted for non-cash impairments, and non-cash convertible debenture) effects resulted in adjusted net income of \$10.6 million for the year ended December 31, 2014;
- Acquired Verano Energy Limited ("Verano") on June 25, 2014 for total net consideration of \$186.2 million, increasing working interest to 70% in Block LLA-32, 63% in Block LLA-17 and 55% in Block LLA-34;
- Converted the Cdn\$85.0 million principal amount of Debentures for an aggregate of 8,339,991 common shares of the Company;
- The Company participated in drilling 38 gross wells in Colombia resulting in 26 oil wells, 6 disposal wells and 6 dry and abandoned, for a success rate of 81 percent; and,
- Increased land holdings in Colombia by 759,076 net acres to 2,176,098 net acres

Three months ended December 31, 2014 (“fourth quarter or Q4”) Highlights

- Achieved a record quarterly oil production of 26,544 barrels per day, an increase of 54% over the prior year comparative period and 18% greater than the 2014 average oil production;
- Generated funds flow from continuing operations of \$49.8 million (\$0.37 per share basic);
- The Company participated in drilling 6 gross wells in Colombia resulting in 5 oil wells and 1 dry and abandoned, for a success rate of 83 percent.

Financial Summary

(Financial figures in 000s except per share amounts)	For the three months ended December 31,		For the year ended December 31,		
	2014	2013	2014	2013	2012
Average daily oil production (bopd)	26,544	17,287	22,526	15,854	11,407
Realized sales price (/bbl)	\$ 60.08	\$ 101.64	\$ 87.60	\$ 104.20	\$ 109.18
Operating netback (/bbl)	\$ 25.21	\$ 60.78	\$ 47.81	\$ 62.70	\$ 73.41
Oil and natural gas sales	\$ 160,584	\$ 166,959	\$ 752,022	\$ 636,577	\$ 523,514
Funds flow from continuing operations ⁽¹⁾	\$ 49,759	\$ 76,304	\$ 293,853	\$ 271,670	\$ 241,569
Per share – basic	0.37	0.70	2.44	2.51	2.23
Per share – diluted ⁽⁴⁾	0.37	0.62	2.42	2.23	1.96
Adjusted net income ⁽¹⁾	\$ (50,996)	\$ 23,201	\$ 10,550	\$ 11,786	\$ 32,628
Per share – basic	(0.38)	0.21	0.09	0.11	0.30
Per share – diluted	(0.38)	0.19	0.09	0.10	0.26
Net Income (loss)	\$ (146,612)	\$ 21,869	\$ (108,773)	\$ 12,672	\$ 39,922
Per share – basic	(1.09)	0.20	(0.90)	0.12	0.37
Per share – diluted ⁽⁵⁾	(1.09)	0.18	(0.90)	0.09	0.31
Capital Expenditures, excluding corporate acquisitions	\$ 83,571	\$ 58,817	\$ 296,876	\$ 233,872	\$ 267,688
Total assets (end of period)	\$ 1,034,415	\$ 854,808	\$ 1,034,415	\$ 854,808	\$ 821,201
Working capital surplus (deficit) ⁽¹⁾⁽³⁾ (end of period)	\$ 3,261	\$ 24,005	\$ 3,261	\$ 24,005	\$ (12,640)
Debenture (end of period) ⁽²⁾	-	66,060	-	66,060	65,657
Bank debt (end of period) ⁽⁶⁾	\$ 35,000	\$ 8,530	\$ 35,000	\$ 8,530	\$ 9,100
Weighted average shares outstanding (000s)					
Basic	134,503	108,460	120,379	108,421	108,403
Diluted	136,140	124,164	122,444	123,535	125,711
Outstanding shares (end of period) (000s)	134,690	108,712	134,690	108,712	108,476

⁽¹⁾ Non-GAAP terms. See “Non-GAAP Terms” on page 26.

⁽²⁾ During August and September 2014, the Cdn\$85.0 million principal amount of Debentures was converted for an aggregate of 8,339,991 common shares of the Company and redeemed for Cdn\$0.3 million in cash.

⁽³⁾ Working capital calculation does not take into consideration the undrawn \$140 million (December 31, 2013 - \$91.5 million) available under the secured credit facility.

⁽⁴⁾ Includes adjustment of debenture cash interest in the funds flow from operations balance.

⁽⁵⁾ Net income diluted has been adjusted for the IFRS accounting effects of changes in the Debentures. For the three months and year ended December 31, 2014 the effect of the debenture is anti-dilutive (three month ended December 31, 2013 – increase of \$0.3 million, year ended December 31, 2012- reduction of \$1.1 million relating to accretion, interest, foreign exchange and gain upon revaluation of the derivative liability).

⁽⁶⁾ Bank credit facility currently has a borrowing base of \$175 million as at December 31, 2014, an increase from the borrowing base of \$100 million at December 31, 2013.

Strategy

The Company’s strategy is to leverage South American experience and capability to create shareholder value. Jurisdictions will be targeted that have stable fiscal regimes coupled with oil-prone hydrocarbon-rich basins in under-explored areas. Parex will apply proven technology used in the Western Canada Sedimentary Basin in basins with large oil-in-place potential. The Company will focus on short cycle time from discovery to bringing new reserves on-stream and use a portfolio approach to manage subsurface and commercial risks.

Principal Properties

As at December 31, 2014, the Company's principal land holdings and interests in exploration and production blocks held by its subsidiaries were as follows:

	Working Interest	Gross Acres	Net Acres
Colombia Llanos Basin			
<u>Operated Properties</u>			
LLA-16, 20, 29 and 30	100%	489,137	489,137
LLA-57	100%	104,532	104,532
Los Ocarros	50%	110,436	55,218
LLA-17	63%	108,726	68,497
El Eden	60%	109,249	65,549
Cabrestero	100%	29,562	29,562
LLA-40	50%	163,090	81,545
LLA-24	100%	147,100	147,100
LLA-26	100%	184,061	184,061
Cebucan	100%	109,150	109,150
Cerrero ⁽¹⁾⁽²⁾	65%	108,973	70,832
Capachos ⁽¹⁾⁽³⁾	50%	32,037	16,019
LLA-32	70%	100,325	70,228
LLA-10 ⁽¹⁾	50%	189,544	94,772
<u>Non-Operated Properties</u>			
LLA-34	55%	82,286	45,257
Balay	10%	4,500	450
Colombia Magdalena Basin			
<u>Operated Properties</u>			
VMM-11 ⁽¹⁾	100%	116,826	116,826
Morpho	100%	51,398	51,398
VIM-1	100%	223,651	223,651
VMM-9	100%	152,314	152,314
Total		2,616,897	2,176,098

Exploration properties that are deemed non-commercial will be relinquished in due course. Accordingly, the gross and net acres described above may decrease over time as lands deemed non-commercial are relinquished. For a description of blocks phase, commitments and letters of credit refer to the Annual Information Form dated March 19, 2014.

⁽¹⁾ Lands are subject to farm-in agreement earning terms and/or regulatory approval.

⁽²⁾ Working interest in the Charcharo evaluation area on the Cerrero block is 25%.

⁽³⁾ Farm-out agreement for Capachos is subject to the execution of the convenio.

2015 Guidance

Parex previously announced revised 2015 guidance that maintains growth and preserves our financial strength in the current oil price environment. Assuming Brent oil prices trade within a range of \$50-\$60/bbl we expect to invest \$145-\$155 million which provides year over year production growth of 18% fully funded by funds flow from operations.

We have budget maintenance capital investment of \$70-\$75 million targeted at development and facility enhancement projects, which is expected to result in average production volumes of 26,500 bopd, which is flat with Q4 2014 average production volumes. Further, Parex will invest \$75-\$80 million on drilling up to 8 exploration wells in 2015. These wells represent contractual drilling commitments. With exploration drilling success we could invest additional capital on exploration facilities and forecast incremental production of 1,000-2,000 bopd on a full year basis.

Previously Parex stated that the 2015 capital budget would be fully funded from funds flow from operations. Since this guidance was released in January 2015, Parex has negotiated reductions in our Colombian service cost structure and has also realized cost reductions through the further depreciation of the Colombian peso. These cost reductions should allow Parex the optionality to fund facilities associated with successful exploration wells and follow up appraisal drilling if warranted following potential exploration success. Additionally, if recent increases in Parex' realized sales prices are sustained, the Company is prepared to fund incremental positioning capital and exploration activities.

Financial and Operational Results

Consolidated Results of Operations

Parex' operations are primarily conducted in Colombia and Canada.

	For the three months ended December 31,		For the year ended December 31,	
	2014	2013	2014	2013
Average daily production				
Colombia – oil (bopd)	26,544	17,287	22,526	15,854
Total (bopd)	26,544	17,287	22,526	15,854
Average daily sales				
Colombia – produced oil (bopd)	26,098	17,365	22,058	15,767
Colombia – purchased oil (bopd)	2,539	490	1,355	973
Total (bopd)	28,637	17,855	23,413	16,740
Operating netback (000s)				
Oil sales excluding risk management contracts	\$ 160,584	\$ 166,959	\$ 752,022	\$ 636,577
Royalties	(16,186)	(18,745)	(90,888)	(77,425)
Net revenue	144,398	148,214	661,134	559,152
Production expense	(26,699)	(15,881)	(90,213)	(57,268)
Transportation expense	(46,191)	(30,663)	(149,454)	(110,523)
Purchased oil expense	(12,462)	(3,297)	(33,187)	(33,633)
Operating netback	\$ 59,046	\$ 98,373	\$ 388,280	\$ 357,728
Operating netback (per bbl) ⁽¹⁾				
Oil sales excluding risk management contracts	\$ 60.08	\$ 101.64	\$ 87.60	\$ 104.20
Royalties	(6.64)	(11.73)	(11.23)	(13.46)
Net revenue	53.44	89.91	76.37	90.74
Production expense	(10.95)	(9.94)	(11.15)	(9.95)
Transportation expense	(17.28)	(19.19)	(17.41)	(18.09)
Operating netback	\$ 25.21	\$ 60.78	\$ 47.81	\$ 62.70

⁽¹⁾ Average daily sales and the operating netback calculation include the Company's working interest sales volumes and excludes purchased oil sales volumes.

The Company's operating netback on a per barrel basis for the three months and year ended December 31, 2014 was \$25.21 (\$60.78 - three months ended December 31, 2013) and \$47.81 (\$62.70 - year ended December 31, 2013) compared to \$53.39 for the third quarter of 2014. The average realized sales price for the three months and year ended was \$60.08/bbl (\$101.64/bbl - three months ended December 31, 2013) and \$87.60/bbl (\$104.20/bbl - year ended December 31, 2013) compared to \$94.40/bbl for the third quarter of 2014.

Royalty charges for the three months and year ended December 31, 2014 were \$6.64/bbl (\$11.73/bbl - three months ended December 31, 2013) and \$11.23/bbl (\$13.46/bbl - year ended December 31, 2013). Royalty charges in the three months ended December 31, 2014 on a per bbl basis have decreased as a result of the drop in oil prices realized.

Production expense for the three months and year ended was \$10.95/bbl (\$9.94/bbl - three months ended December 31, 2013) and \$11.15/bbl (\$9.95/bbl - year ended December 31, 2013).

Transportation expense per barrel for the three months and year ended was \$17.28/bbl (\$19.19/bbl - three months ended December 31, 2013) and \$17.41/bbl (\$18.09/bbl - year ended December 31, 2013) and compared to \$17.80/bbl for the third quarter of 2014. Transportation and marketing alternatives continue to be examined by the Company in an effort to maximize the net proceeds from production in Colombia.

Overall the price of the Company's benchmark Brent price decreased by \$26.39/bbl in the fourth quarter as compared to the third quarter of 2014 while the operating netback declined by \$28.18/bbl in the same period, mainly a result of a widening of the company's realized price as compared to the Brent reference price (see Commodity Prices) due to timing of crude export sales in the rapidly declining oil price environment.

Colombian Oil and Gas Sales

a) Average Daily Crude Oil Production and Sales Volumes (bopd)

	For the three months ended December 31,		For the year ended December 31,	
	2014	2013	2014	2013
Block LLA-34 (Tigana, Max, Tua & Tarotaro fields)	11,053	4,863	9,325	3,470
Block LLA-32 (Kananaskis, Carmentea, Maniceno and Bandola fields)	5,723	303	3,041	445
Block Los Ocarros (Las Maracas field)	3,201	6,177	5,000	5,266
Block Cabrestero (Kitaro & Akira fields)	2,757	280	1,492	476
Block LLA-16 (Kona, Sulawesi, Java and Malawi fields)	1,122	3,931	1,935	5,100
Block LLA-30 (Adalia field)	1,168	937	816	463
Block LLA-40 (Bergonia and Celtis fields)	791	-	300	-
Other	729	796	617	634
Total Production	26,544	17,287	22,526	15,854
Inventory (build) draw and consumption	(446)	78	(468)	(87)
Colombia average daily oil sales of produced oil	26,098	17,365	22,058	15,767
Purchased oil	2,539	490	1,355	973
Sales Volumes	28,637	17,855	23,413	16,740

Production for the fourth quarter of the year averaged 26,544 bopd, an increase of approximately 54 percent from the fourth quarter average of 2013. Production increased 5 percent from the third quarter of 2014 mainly as a result of production attributable to Block LLA-32, and the Cabrestero block.

Average production in January and February 2015 has remained at approximately 26,550 bopd, in line with Company's previously announced guidance and flat with Q4 average production. The Company has shut-in approximately 1,000 bopd of higher cost production, offset by additional production at Cabrestero and LLA-34.

b) Average Reference and Realized Prices

	For the three months ended December 31,		For the year ended December 31,	
	2014	2013	2014	2013
Reference Prices				
Brent (\$/bbl)	77.07	109.21	99.56	108.64
WTI (\$/bbl)	73.20	97.34	93.20	97.91
Vasconia (\$/bbl)	71.42	101.58	93.03	103.70
Average Realized Prices				
Realized sales price (\$/bbl)	60.08	101.64	87.60	104.20
Realized oil hedging gain (loss) (\$/bbl)	2.33	(0.85)	0.94	(0.22)
Realized price after hedging (\$/bbl)	62.41	100.79	88.54	103.98
Realized price (discount) as percentage of Brent (%)	(22.0)	(6.9)	(12.0)	(4.1)
Realized price (discount) premium as percentage of WTI (%)	(17.9)	4.4	(6.0)	6.4

During Q4 2014, the differential between Brent reference pricing and our realized sale price was approximately \$17/bbl versus posted Vasconia differential of \$5.65/bbl, which would be in line with our historical differential. This approximately \$11/bbl sales price difference (estimated funds flow from operations impact of \$0.14/share basic) is due to the rapid decline of Brent oil pricing during the quarter coupled with the timing of crude liftings for exportation during the quarter. The Company also chose to reduce crude oil inventory before the end of the quarter resulting in 260,000 bbls being sold and priced in the last week of December at the time of the lowest Brent crude oil prices in the quarter. Although Parex delivers crude oil daily into transportation system the sales price is determined when crude is lifted for export.

To date in 2015, the Brent crude oil price to our realized sales price differential is in line with our historical Vasconia differential on a per bbl basis.

The table below provides a quarter-by-quarter view of Parex' historical pricing in Colombia:

Average price for the period	Q4 2014	Q3 2014	Q2 2014	Q1 2014	Q4 2013
Brent (\$/bbl)	77.07	103.46	109.69	108.17	109.21
Parex realized sales price (\$/bbl)	60.08	94.40	104.53	103.42	101.64
Parex realized price (discount) as percentage of Brent (%)	(22.0)	(8.8)	(4.7)	(4.4)	(6.9)

c) Oil Revenue

Fourth quarter 2014 oil revenue decreased \$6.4 million or 4 percent as reconciled in the table below to the fourth quarter of 2013:

(\$000s)	
Oil revenue, three months ended December 31, 2013	\$ 166,959
Sales volume of produced oil, an increase of 54% (9,257 bopd)	86,561
Sales volume of purchased oil, an increase of 418% (2,049 bopd)	19,160
Sales price decrease of 41%	(112,096)
Oil revenue, three months ended December 31, 2014	\$ 160,584

Oil sales volumes increased in the three months ended December 31, 2014 compared to the same period in 2013 due to the Verano acquisition completed in late June 2014, along with an incremental increase in oil production from the acquired fields and appraisal drilling activities.

d) Colombian Crude Oil Inventory in Transit

(\$000s)	
For the years ended December 31,	2014 2013
Crude oil in transit	\$ 10,959 \$ 8,695

As at December 31, 2014, the Company had 252,031 bbls of crude oil inventory in transit, which was injected into the Colombian pipelines. The inventory was valued based on direct and indirect expenditures (including production costs, certain transportation costs, depletion expense and royalty expense) at approximately \$43/bbl (\$63/bbl - 2013) incurred in bringing the crude oil to its existing condition and location. The cost per bbl of crude oil inventory has decreased largely due to decreased depletion costs per bbl. A reconciliation of the crude oil inventory in transit volumes is provided below:

(mbbls)	
For the periods ended December 31,	2014 2013
Crude oil inventory in transit - beginning of the period	137.0 98.8
Oil production	8,222.0 5,786.8
Oil sales	(8,545.7) (6,110.5)
Purchased oil	494.5 370.3
Company consumption and oil losses	(55.8) (8.4)
Crude oil inventory in transit - end of the period	252.0 137.0

As a percentage of the quarter's crude oil production, crude oil inventory has remained in line in Q4, 2014 at approximately 10 percent as compared to 2013 at 9 percent. A reconciliation of quarter to quarter crude oil inventory movements is provided below:

(mbbls)	
For the periods ended	Dec. 31, 2014 Sept. 30, 2014 June 30, 2014 Mar. 31, 2014
Crude oil inventory in transit - beginning of the period	249.4 195.4 73.6 137.0
Oil production	2,442.1 2,316.2 1,805.5 1,658.3
Oil sales	(2,634.6) (2,424.1) (1,745.7) (1,741.5)
Company consumption and oil losses	(38.5) (9.2) (5.3) (2.8)
Purchased oil	233.6 171.1 67.3 22.6
Crude oil inventory in transit - end of the period	252.0 249.4 195.4 73.6

The Company is experiencing, on average, two-thirds of period ending crude oil inventory being sold within the following month, however build and draw down of crude oil inventory from period to period are subject to factors that the Company does not control such as timing of the number of shipments from storage to export.

e) Purchased Oil

(mbbls)	For the three months ended December 31,		For the year ended December 31,	
	2014	2013	2014	2013
Oil purchased	233.6	45.1	494.5	370.3
Purchased oil sales	(233.6)	(45.1)	(494.5)	(370.3)
Purchased oil net change in inventory	-	-	-	-

From time to time the Company will purchase crude oil from partners. The table above shows the effect of purchased oil on ending crude oil inventory balances. At December 31, 2014 and December 31, 2013 the Company did not have any third party purchased oil in inventory.

	For the three months ended December 31,		For the year ended December 31,	
	2014	2013	2014	2013
Purchased oil expense (\$000s)	\$ 12,462	\$ 3,297	\$ 33,187	\$ 33,633

Purchased oil expense for the three months and year ended December 31, 2014 was \$12.5 million and \$33.2 million as compared to \$12.9 million in the preceding quarter and \$3.3 million and \$33.6 million for the three months and year ended December 31, 2013. Transportation costs are incurred by the Company to transport purchased oil to sale delivery points.

Colombian Royalties

	For the three months ended December 31,		For the year ended December 31,	
	2014	2013	2014	2013
Royalties (\$000s)	\$ 16,186	\$ 18,745	\$ 90,888	\$ 77,425
Per unit (\$/bbl)	6.64	11.73	11.23	13.46
Percentage of sales ⁽¹⁾	10.9%	11.5%	12.6%	12.8%

⁽¹⁾ Calculated based on Company working interest sales volumes excluding purchased oil volumes sold

In the fourth quarter royalties as a percentage of sales was 10.9% as compared to the previous quarter of 11.4%. The decrease is mainly a function of decreased production from fields subject to the High Price Share royalty. The higher royalty regime comes into effect when accumulated production of any production area, inclusive of royalty volumes, exceeds 5 million barrels, and in the event international reference prices exceed pricing determined in the contract. The calculation is described as a “High Price Share” in the Company’s Annual Information Form dated March 19, 2014, and may be accessed through the SEDAR website at www.sedar.com.

The Company expects that the overall royalty as a percentage of sales will continue to decrease in 2015 in the current oil price environment, until the point when the Tua and Tigana fields will be subject to the High Price Share royalty, estimated to be in the second quarter of 2015.

Colombian Production Expense

	For the three months ended December 31,		For the year ended December 31,	
	2014	2013	2014	2013
Production expense (\$000s)	\$ 26,699	\$ 15,881	\$ 90,213	\$ 57,268
Per unit (\$/bbl)	10.95	9.94	11.15	9.95

A breakdown of the production expense on a per bbl basis between operated and non-operated fields are provided below:

	For the three months ended December 31,		For the year ended December 31,	
	2014	2013	2014	2013
Per unit (\$/bbl) – based on sales volumes – operated ⁽¹⁾	12.38	8.14	11.56	8.09
Per unit (\$/bbl) – based on sales volumes – non-operated ⁽¹⁾	9.07	14.11	10.64	15.40

⁽¹⁾ Calculated based on Company working interest sales volumes excluding purchased oil volumes sold.

Production expense includes the cost of activities in the field to operate wells and facilities, lift to surface, gather, process, treat and store production.

Production expense for the fourth quarter on a per barrel basis of \$10.95/bbl is lower in comparison of the third quarter of \$12.32/bbl. Operated properties production expense in the fourth quarter was \$12.38/bbl compared to \$12.79/bbl for the third quarter and non-operated properties production expense was \$9.07/bbl for the fourth quarter compared to \$11.78/bbl for the third quarter. The quarter over quarter decrease in the non-operated properties production expense relates to Block LLA-34 as fixed operating cost absorption has increased as a result of increased production from this Block.

Production expense for the year ended December 31, 2014 on a per barrel basis is \$11.15/bbl compared to \$9.95/bbl for the year ended December 31, 2013. The increase is primarily due to operated production expenses on a per barrel basis being higher as decreased fixed cost absorption and higher water handling costs are experienced on operated fields at Kona and Las Maracas where oil production has declined.

For 2015 the Company expects production cost savings related to the depreciation of the Colombian peso as approximately 50% of production costs are denominated in Colombian pesos. Further, the Company has been working with its vendors to seek price reductions in the current oil price environment and has temporarily shut-in higher cost production.

Colombian Transportation Expense

		For the three months ended December 31,		For the year ended December 31,	
		2014	2013	2014	2013
Transportation expense (\$000s)	\$	46,191	\$ 30,663	\$ 149,454	\$ 110,523
Per unit (\$/bbl)		17.28	19.19	17.41	18.09

Transportation expense includes trucking costs incurred to transport production to several offloading stations for sale and in some instances an oil transportation tariff from delivery point to the buyer's facility. For the three months ended December 31, 2014, the cost of transportation on a per barrel basis has decreased to \$17.28/bbl (\$19.19/bbl - three months ended December 31, 2013) and from the third quarter of 2014 of \$17.80/bbl mainly as a result of a larger percentage of the company's oil being sold through pipelines and not trucked to the coast for export. For the year ended December 31, 2014, the cost of transportation on a per barrel basis has decreased to \$17.41/bbl from year ended December 31, 2013 of \$18.09/bbl. Parex expects that transportation expense per barrel will decrease from those realized in Q4 2014 due to many factors including the depreciation of the Colombian peso and the increased availability of pipeline capacity resulting in lower pipeline tariffs.

General and Administrative Expense ("G&A")

(\$000s)		For the three months ended December 31,		For the year ended December 31,	
		2014	2013	2014	2013
Gross G&A	\$	12,125	\$ 14,519	\$ 44,037	\$ 43,458
G&A recoveries		(411)	(771)	(1,587)	(2,948)
Capitalized G&A		(2,488)	(5,583)	(8,646)	(8,409)
Total G&A		9,226	8,165	33,804	32,101
G&A reclassified to discontinued operations ⁽¹⁾		(301)	(485)	(1,273)	(1,747)
Net G&A expense	\$	8,925	\$ 7,680	\$ 32,531	\$ 30,354
Per unit (\$/bbl) ⁽²⁾	\$	3.66	\$ 4.83	\$ 3.96	\$ 5.25

⁽¹⁾ Due to the sale of Parex Resources (Trinidad) Ltd.

⁽²⁾ Calculated based on Company working interest production volumes.

Net G&A from continuing operations was \$32.5 million for the twelve months ended December 31, 2014 compared to \$30.4 million for the same period in 2013. These costs primarily consist of management and administrative salaries, legal and professional fees, office rent, insurance, travel and other administrative expense and employee costs. Costs were higher than the comparative period as a result of increased activity levels. For the fourth quarter of 2014 net G&A was mainly comprised of \$7.0 million relating to staff, consultants and professional services and the balance to other expenses. A total of 278 full-time-equivalents in three locations were working for Parex as at December 31, 2014 and throughout the fourth quarter compared to 206 as at December 31, 2013. On a per barrel basis net G&A for the year has declined 24% from the comparative period.

The Company's G&A expense is mainly denominated in local currencies of COP and Cdn dollar which have both depreciated significantly against the USD in the second half of 2014.

Share-Based Compensation Expense

(\$000s)		For the three months ended December 31,		For the year ended December 31,	
		2014	2013	2014	2013
Share-based compensation expense	\$	1,274	\$ 1,296	\$ 5,746	\$ 5,409
Restricted share units expense		925	538	2,745	1,121
Share appreciation rights expense		(5,107)	564	4,005	344
Total (recovery) expense	\$	(2,908)	\$ 2,398	\$ 12,496	\$ 6,874
SARs (recovery) expense reclassified as discontinued operations		(171)	83	(171)	-
Total (recovery) expense – continuing operations	\$	(3,079)	\$ 2,481	\$ 12,325	\$ 6,874

Share-based compensation expense was \$12.5 million for the twelve months ended December 31, 2014 compared to \$6.9 million for the same period in 2013. Share-based compensation expense relating to stock options was \$5.7 million for the twelve months ended December 31, 2014 compared to \$5.4 million for the same period in 2013. As at December 31, 2014, stock options outstanding were 7,577,010 equaling 6 percent of the common shares outstanding at the end of the fourth quarter. A total of 2,923,478 options were exercised, 1,889,375 options were granted, and 84,250 options were forfeited during the twelve months ended December 31, 2014. As at December 31, 2014, the weighted average fair value upon grant date of the options outstanding based upon the Black-Scholes option value methodology was Cdn\$3.75 per option (December 31, 2013 - Cdn\$2.32 per option). The weighted average grant price for the twelve months ended December 31, 2014 was Cdn\$10.16 per option (December 31, 2013 - Cdn\$6.02).

Share appreciation rights (“SARs”) expense was a recovery of \$5.1 million in the fourth quarter of 2014 (fourth quarter 2013 - \$0.6 million expense) as a result of the share price of the company decreasing in the period from Cdn\$12.45/share as at September 30 to Cdn\$7.58/share as at December 31, 2014. SARs expense was \$4.0 million for the twelve months ended December 31, 2014 compared to \$0.3 million for the same period in 2013. As at December 31, 2014, 2,606,643 SARs were outstanding all of which were granted to employees in Colombia and Trinidad & Tobago. The weighted average exercise price at December 31, 2014 of the SARs outstanding was Cdn\$7.12 per SAR (December 31, 2013 - Cdn\$5.77 per SAR).

As at December 31, 2014, the total SARs liability accrued is \$4.4 million (December 31, 2013 - \$3.2 million).

Restricted share unit (“RSUs”) expense was \$2.7 million for the twelve months ended December 31, 2014 compared to \$1.1 million for the same period in 2013. As at December 31, 2014, RSUs outstanding were 1,625,885 equaling 1 percent of the common shares outstanding at the end of the fourth quarter. A total of 26,096 units were exercised, 789,050 units were granted, and 5,869 units were forfeited during the twelve months ended December 31, 2014. As at December 31, 2014 the fair value upon grant date of the units outstanding was Cdn\$10.16 per unit (December 31, 2013 - Cdn\$5.95 per unit).

Depletion, Depreciation and Amortization Expense (“DD&A”)

		For the three months ended December 31,		For the year ended December 31,	
		2014	2013	2014	2013
DD&A (\$000s) total	\$	51,668	\$ 55,297	\$ 218,490	\$ 214,131
DD&A reclassified to discontinued operations		(3)	(7)	(19)	(38)
DD&A – continuing operations	\$	51,665	\$ 55,290	\$ 218,471	\$ 214,093
Per unit (\$/bbl) ⁽¹⁾		21.16	34.77	26.56	37.00

⁽¹⁾ DDA per unit (\$/bbl) is calculated using Company working interest production volumes and does not include inventory adjustments.

DD&A is primarily associated with production assets in Colombia and also includes the depreciation and amortization of corporate assets such as computer equipment, office furniture and leasehold improvements. The net carrying value of production assets are depleted using the unit-of-production method by determining the ratio of production in the period to the related proved plus probable reserves, while also taking into account estimated future development costs necessary to bring those reserves into production.

For the fourth quarter of 2014, future development costs of \$360.8 million (three months ended December 31, 2013 - \$232.4 million) were included in the depletion calculation. Fourth quarter 2014 depletion was \$51.3 million compared to \$55.0 million for the same period in 2013. Fourth quarter 2014 DD&A of \$21.16/bbl is lower than the comparative period of \$34.77/bbl due to the 114% increase in proved and probable reserves at December 31, 2014. This decrease in full year 2014 DD&A per barrel is also a result of drilling success and increased reserves as compared to the prior period. The remaining DD&A relates to office fixtures and equipment which is depreciated over the assets estimated useful lives’.

For the year ended December 31, 2014 DD&A was \$218.5 million (\$26.56/bbl) as compared to \$214.1 million (\$37.00/bbl) for the prior year. The increase in DD&A is a result of the 42% increase in oil production volumes in 2014 offset by lower per barrel DD&A cost.

Foreign Exchange

(\$000s)	For the three months ended December 31,		For the year ended December 31,	
	2014	2013	2014	2013
Foreign exchange gain	\$ (7,261)	\$ (2,562)	\$ (9,742)	\$ (7,236)
Foreign exchange (gain) loss reclassified to discontinued operations	-	2	(2)	34
Foreign exchange gain– continuing operations	\$ (7,261)	\$ (2,564)	\$ (9,740)	\$ (7,270)
Foreign Exchange Rates				
CAD\$/USD\$	0.88	0.95	0.91	0.97
Colombian peso/USD\$	2,169	1,913	1,998	1,869

The Company's main exposure to foreign currency risk relates to the pricing of foreign currency denominated in Canadian dollars and Colombian pesos, as the Company's functional currency is the US dollar. The Company has exposure in Colombia and Canada on costs, such as capital expenditures, local wages, royalties and income taxes, all of which may be denominated in local currencies. The main drivers of foreign exchange (gains) losses are the revaluation of the Colombian peso denominated income tax, accounts payable and accounts receivable to USD at period end dates. During the three and twelve months ended December 31, 2014, the foreign exchange gain of \$7.3 million and \$9.7 million relates to the Colombian peso and Canadian dollar depreciating in value from the exchange rates at period end dates. Unrealized foreign exchange gains and losses may be reversed in the future as a result of fluctuations in exchange rates and are recorded in the Company's consolidated statement of comprehensive income (loss). For the three months and year ended December 31, 2014, \$0.5 million loss and \$3.6 million gain of the foreign exchange gain is realized and \$7.8 million gain and \$6.1 million gain is unrealized.

For the twelve month period ended December 31, 2013, a foreign exchange gain of \$2.6 million was recognized primarily due to the Canadian dollar exchange rate at December 31, 2013 being lower than the opening January 1, 2013 exchange rate with the main driver being the conversion for reporting purposes of the CAD denominated Debenture to USD.

On August 12, 2014 the Company issued a notice of redemption to holders of its then outstanding Cdn\$85.0 million Convertible Debentures with the redemption date set as September 24, 2014. During August and September 2014, the Cdn\$85.0 million principal amount of Debentures was converted for an aggregate of 8,339,991 common shares of the Company and redeemed for \$0.3 million in cash. The foreign exchange gain on the Debenture was offset by a corresponding loss on the Cross Currency Interest Rate Swap. In association with the settlement of the Debenture, the Cross Currency Interest Rate Swap has also been terminated in the current period (refer to the "Risk Management" section for additional information).

Going forward the company expects less foreign exchange adjustments due to the redemption and conversion of the Canadian dollar denominated Debenture. There will still however continue to be foreign exchange impacts on Colombian peso denominated balance sheet accounts such as Colombian income taxes payable and peso denominated accounts receivable and accounts payable. The majority of crude oil sales are denominated and collected in US dollars.

On September 3, 2014, the Company entered into two foreign currency risk management contracts with the purpose of hedging a portion of our 2014 Colombian cash tax payments to be made in April and June 2015. Both contracts have principal amounts of \$15 million each with terms ending April 30, 2015. The put option is at a price of 1,850 and the call option is at a price of 2,100 Colombian pesos/USD.

The Company reviews its exposure to foreign currency variations on an ongoing basis and maintains foreign denominated cash deposits primarily in Canada and Colombia and USD deposits in Barbados.

Net Finance Expense

(\$000s)	For the three months ended December 31,		For the year ended December 31,	
	2014	2013	2014	2013
Interest expense and bank charges	\$ 1,651	\$ 1,949	\$ 7,042	\$ 6,883
Accretion on convertible debentures	-	1,107	3,210	4,163
Accretion on decommissioning and environmental liabilities	334	274	1,127	581
Loss (gain) on derivative financial liability	-	1,332	23,707	(885)
Gain on settlement of convertible debentures	-	-	(557)	-
Amortization of debt issuance costs	-	167	475	627
Realized loss (gain) on foreign currency risk management contracts	-	2,527	2,672	(409)
Unrealized loss on foreign currency risk management contracts	1,975	-	1,975	5,694
Loss on disposition of tangible assets	136	-	731	-
Interest and other income	79	62	(1,332)	(1,039)
Net finance expense	\$ 4,175	\$ 7,418	\$ 39,050	\$ 15,615
Finance expenses reclassified to discontinued operations	(138)	(11)	(743)	(25)
Net finance expense - continuing operations	\$ 4,037	\$ 7,407	\$ 38,307	\$ 15,590

	For the three months ended December 31,		For the year ended December 31,	
	2014	2013	2014	2013
Non-cash finance expense	\$ 2,445	\$ 5,598	\$ 30,668	\$ 10,180
Cash finance expense	1,730	1,820	8,382	5,435
Net finance expense	\$ 4,175	\$ 7,418	\$ 39,050	\$ 15,615

On August 12, 2014 the Company issued a notice of redemption to holders of its then outstanding Cdn\$85.0 million Convertible Debentures (the “Debentures”), with the redemption date set as September 24, 2014. During August and September 2014, the Cdn\$85.0 million principal amount of Debentures was converted by the Debenture holders for an aggregate of 8,339,991 common shares of the Company and Debentures not converted were redeemed for \$0.3 million in cash. A gain of \$0.6 million on the settlement of the Debentures and the related derivative financial liability was recognized in finance expense in the consolidated statement of comprehensive income (loss) during the year ended December 31, 2014 (refer to the “Debenture” section for additional information).

Interest expense relates to the Debenture and interest on the credit facility. As the Debenture was redeemed on September 24, 2014, interest expense on Debentures for the three months ended December 31, 2014 was \$nil (three months ended December 31, 2013 - \$1.1 million). The interest expense on the Debentures up to the date of redemption for the year ended December 31, 2014 was \$2.9 million (December 31, 2013 - \$4.3 million). The accretion expense for the debentures for the three months ended December 31, 2014 was \$nil (three months ended December 31, 2013 - \$1.1 million). The debenture accretion expense was \$3.2 million for the year ended December 31, 2014 (December 31, 2013 - \$4.2 million). The accretion is related to the Debentures’ liability portion being accreted under the effective interest rate method until the date of redemption of the Debentures.

For the year ended December 31, 2014, a \$23.7 million loss (year ended December 31, 2013 - \$0.9 million gain) was recognized on the conversion/redemption feature of the Debenture. During August and September 2014, the Cdn\$85.0 million principal amount of Debentures was converted for an aggregate of 8,339,991 common shares of the Company and redeemed for Cdn\$0.3 million in cash.

Risk Management

Management of cash flow variability is an integral component of Parex’ business strategy. Changing business conditions are monitored regularly and, where material, reviewed with the Board of Directors to establish risk management guidelines to be used by management. The risk exposure inherent in movements in the price of crude oil, fluctuations in the US/COP exchange rate and interest rate movements are all proactively reviewed by Parex and as considered appropriate they may be managed through the use of derivatives with financial institutions that are members of Parex’ credit facility. The Company considers these derivative contracts to be an effective means to manage risks of material reductions in cash flow.

The company has elected to not use hedge accounting and, accordingly, the fair value of the financial contracts is recorded at each period-end. The fair value may change substantially from period to period depending on commodity and foreign exchange forward strip prices for the financial contracts outstanding at

the balance sheet date. The change in fair value from period-end to period-end is reflected in the earnings for that period. As a result, earnings may fluctuate considerably based on the period-ending commodity and foreign exchange forward strip prices. As of December 31, 2014 the Company did not have any crude risk management contracts in place. However, the Company considers its relatively low debt levels to be its most effective long-term protection from variable and inherently uncertain future commodity prices and foreign exchange rates.

a) Risk Management Contracts – Brent Crude

As at December 31, 2014, the Company had no outstanding crude contracts in place. The table below summarizes (gain) loss on the commodity risk management contracts that were in place during the year ended December 31, 2014 and 2013:

(\$000s)		For the three months ended December 31,		For the year ended December 31,	
		2014	2013	2014	2013
Realized loss (gain) on commodity risk management contracts	\$	(6,232)	\$ 1,353	\$ (8,054)	\$ 1,239
Unrealized loss on commodity risk management contracts		-	793	-	1,459
Total	\$	(6,232)	\$ 2,146	\$ (8,054)	\$ 2,698

The Company's net unrealized derivative (gain) loss on risk management contracts for the year ended December 31, 2014 was \$nil (December 31, 2013 - loss of \$1.5 million). The realized gain on commodity risk management contracts of \$6.2 million and \$8.1 million for the three and twelve months ended December 31, 2014 is attributed to the company monetizing put options in the fourth quarter of 2014.

Subsequent to December 31, 2014, Parex entered into the following ICE Brent priced crude oil risk management contracts:

Period Hedged	Reference	Type	Volume bbls/d	Price/bbl
March 1, 2015 to March 31, 2015	ICE Brent	Collar	5,000	\$55.00-\$66.60
March 1, 2015 to March 31, 2015	ICE Brent	Collar	3,000	\$55.00-\$68.00
April 1, 2015 to April 30, 2015	ICE Brent	Collar	5,000	\$55.00-\$68.25
April 1, 2015 to April 30, 2015	ICE Brent	Collar	3,000	\$55.00-\$69.75
April 1, 2015 to April 30, 2015	ICE Brent	Collar	2,000	\$55.00-\$67.00
May 1, 2015 to May 31, 2015	ICE Brent	Collar	5,000	\$55.00-\$68.75

b) Risk Management Contracts – Foreign Currency

The following is a summary of the foreign currency risk management contracts in place as at December 31, 2014:

Period Hedged	Reference	Type	Amount USD	Price (COP)
September 5, 2014 to April 30, 2015	Colombian Peso	Put	\$15 million	1,850
September 5, 2014 to April 30, 2015	Colombian Peso	Call	\$15 million	2,100

Associated with the Cdn\$85.0 million of Debentures, on December 30, 2012 the Company entered into a Cross Currency Interest Rate Swap ("CCIRS") with two financial institutions who are members of the Company's credit facility. Under the terms of the CCIRS, the US dollar amount of the Debenture was fixed for purposes of interest and principal repayment at a notional amount of \$85.7 million as follows:

	Type	Receive Notional Principal (Cdn\$)	Fixed annual rate (Cdn%)	Pay Notional Principal (US\$)	Fixed annual rate (US%)
December 30, 2012 – June 30, 2016	Swap	85,000,000	5.25%	85,685,565	4.45%

In association with the settlement of the Debenture (see the "Debenture" section for additional details), the CCIRS was terminated in the third quarter of 2014.

The table below summarizes the losses (gains) on the foreign currency risk management contracts:

(\$000s)	For the three months ended December 31,		For the year ended December 31,	
	2014	2013	2014	2013
Realized loss (gain) on foreign currency risk management contracts	\$ -	\$ (191)	\$ 2,672	\$ (409)
Unrealized loss on foreign currency risk management contracts	1,975	2,718	1,975	5,694
Total	\$ 1,975	\$ 2,527	\$ 4,647	\$ 5,285

The realized loss (gain) represents the foreign currency risk management contracts and the CCIRS payments settled during the period. The unrealized loss (gain) represents the fair value change of the underlying foreign currency risk management contracts as at the balance sheet to be settled in the future. While a loss on the settlement of the CCIRS was realized, the Company realized a reduction in the USD denominated interest rate up until approximately June 2014.

Income Tax

The components of tax expense for the three and twelve months ended December 31, 2014 and 2013 were as follows:

(\$000s)	For the three months ended December 31,		For the year ended December 31,	
	2014	2013	2014	2013
Current tax expense	\$ 7,368	\$ 10,692	\$ 52,184	\$ 46,274
Deferred tax recovery	(28,022)	(7,025)	(19,539)	(2,994)
Total tax expense	\$ (20,654)	\$ 3,667	\$ 32,645	\$ 43,280

The current and deferred tax expense relates to the Company's operations in Colombia. Current tax in the fourth quarter was \$7.4 million as compared to \$10.7 million in the comparative three month period. The current tax expense decreased from the third quarter of 2014 of \$13.6 million as result of decreased Colombian cash flows and increased capital expenditures. In the quarter the tax expense as a percentage of Colombian cash flows was 12% compared to the company historical average being 13-15%. This decrease is a result of the utilization of Verano acquired non-capital losses and capital expenditures being greater than cash flow.

Deferred tax in the fourth quarter of 2014 was a recovery of \$28.0 million and a recovery of \$19.5 million for the year ended December 31, 2014 (\$7.0 million and \$3.0 million recovery for the three and twelve months ended December 31, 2013), as a result of a narrowing of the book and tax basis in Colombian subsidiaries from the non-cash impairments recorded on E&E and PP&E assets, however partially offset by a depreciation in the Colombian peso in both the three and twelve month periods and increases to Colombian tax rates beginning in 2015 through 2018. In the December of 2014, the Colombian government enacted new legislation containing tax rate changes effective January 1, 2015. The increases will result in a consolidated income tax of: 39% for 2015; 40% for 2016; 42% for 2017; and 43% for 2018. Under current legislation, the consolidated rate is set to revert to 34% in 2019 and onwards.

The calculation of current and future income tax in Colombia is based on a number of variables which can cause swings in current and future income tax. These variables include the year end producing reserves used in calculating depletion for tax purposes and the timing and number of dry hole write offs permissible for Colombian tax purposes. Accordingly estimating tax expense during the year is inherently difficult. The effective current tax rate for the twelve months ended December 31, 2014 on Colombian segmented operating cash flows was 13%.

Colombian Net Wealth Tax ("NWT")

On December 23, 2014 the Colombian Congress passed a law imposing a Net Wealth Tax ("NWT") levied on Colombian companies. The tax is assessed and becomes payable on the opening equity as at January 1st of each year beginning in 2015 extending until 2017, at rates from 1.15% in 2015 to 0.4% in 2017.

The Company's NWT for 2015 is expected to be \$3.5 million and will be paid in two equal semi-annual installments in 2015.

Capital Expenditures

For the year ended December 31, (\$000s)	Colombia ⁽¹⁾		Trinidad & Tobago		Canada		Total	
	2014	2013	2014	2013	2014	2013	2014	2013
Acquisition of unproved properties	14,551	3,309	-	958	-	-	14,551	4,267
Geological and geophysical	11,406	9,150	-	2,305	-	-	11,406	11,455
Drilling and completion	234,842	174,494	-	(1,991)	-	-	234,842	172,503
Well equipment and facilities	34,204	31,148	-	851	-	-	34,204	31,999
Other	641	1,033	717	(2)	515	128	1,873	1,159
	\$ 295,644	\$ 219,134	\$ 717	\$ 2,121	\$ 515	\$ 128	\$ 296,876	\$ 221,383
Property acquisition costs	-	12,489	-	-	-	-	-	12,489
Total capital expenditures	\$ 295,644	\$ 231,623	\$ 717	\$ 2,121	\$ 515	\$ 128	\$ 296,876	\$ 233,872

⁽¹⁾ Excludes Verano and Sorigenia corporate acquisition costs.

For the three months ended December 31, (\$000s)	Colombia		Trinidad & Tobago		Canada		Total	
	2014	2013	2014	2013	2014	2013	2014	2013
Acquisition of unproved properties	7,117	728	-	(145)	-	-	7,117	583
Geological and geophysical	4,856	(1,160)	-	-	-	-	4,856	(1,160)
Drilling and completion	58,876	46,704	-	(206)	-	-	58,876	46,498
Well equipment and facilities	11,666	12,458	-	-	-	-	11,666	12,458
Other	88	360	551	(2)	417	80	1,056	438
Total capital expenditures	\$ 82,603	\$ 59,090	\$ 551	\$ (353)	\$ 417	\$ 80	\$ 83,571	\$ 58,817

a) Capital Expenditures Summary

During the twelve months ended December 31, 2014 the Company incurred \$296.9 million of capital expenditures compared to \$233.9 million in the same period of 2013. During 2014 the Company drilled 38 wells (23.75 net), compared to 37 wells (24.2 net) in 2013.

In the fourth quarter of 2014 the Company drilled 6 wells (4.15 net) in Colombia compared to 9 wells (6.1 net) in the comparative period. Drilling and completion costs during the fourth quarter totaled \$58.9 million, all of which related to drilling and completion and capitalized workover costs in Colombia. Spending on well equipment and facilities was \$11.7 million in the quarter, all focused in Colombia. The drilling and completion costs per well on a net basis were \$14.2 million in the fourth quarter of 2014 versus \$7.7 million in the comparative period, this difference was primarily related to pre-drill civil work and pad construction in Q4 for our 2015 drilling program.

In the fourth quarter of 2014 the Company's Colombian operations utilized 3 drilling rigs and 2 service rigs plus equipment utilized on the non-operated block in the quarter. The level of activity increased in the fourth quarter of 2014 from the third quarter of 2014 as Parex invested \$82.6 million in the fourth quarter as compared to \$56.8 million in the previous third quarter of 2014. However as oil prices declined, Parex reduced its drilling program and by the end of the fourth quarter only 1 drilling rig was active drilling the Tilo-1 exploration prospect.

During the year ended December 31, 2014 capital expenditures of \$296.9 million (before corporate acquisition costs) were self funded from funds flow from operations of \$293.9 million. The Company has maintained its ability to fund growth from cash flow since 2012.

Corporate Acquisitions

a) Verano acquisition

On June 25, 2014, Parex acquired all of the outstanding shares of Verano Energy Limited ("Verano") which assets primarily consist of interests in three exploration blocks located in Colombia's Llanos Basin (the "Verano Acquisition"). The Company paid total net consideration of \$186.2 million. The Verano Acquisition increases the Company's working interest in Block LLA-32 to 70%, in Block LLA-17 to 63% working interest and in Block LLA-34 to 55% working interest.

The consolidated statement of comprehensive income (loss) includes results of operation of Verano since the closing date of June 25, 2014 and expensed transaction costs associated with the Verano Acquisition of \$0.6 million.

This transaction has been accounted for using the acquisition method whereby the assets acquired and the liabilities assumed are recorded at fair values. As the fair value of the identifiable assets was determined to be less than the purchase price, goodwill of \$12.2 million arose on the transaction. The following table summarizes the recognizable assets acquired and consideration paid pursuant to the acquisition:

Assets acquired and liabilities assumed⁽¹⁾		
Working capital deficiency	\$	(31,537)
PP&E		247,617
E&E assets		9,863
Deferred tax liability		(50,057)
Decommissioning and environmental liabilities		(1,852)
Goodwill		12,200
	\$	186,234

⁽¹⁾ The above amounts are estimates, which were made by management at the time of the preparation of these financial statements based on information then available. Amendments may be made to these amounts as values subject to estimate are finalized.

Consideration for the acquisition		
Issuance of common shares	\$	169,333
Cash paid		75,415
Cash acquired		(53,115)
Settlement of pre-existing relationship		(5,399)
Total net consideration paid	\$	186,234

An adjustment has been made to the fair values of assets acquired and liabilities assumed during the year ended December 31, 2014 resulting in an increased working capital deficiency and goodwill.

Included in the working capital deficiency of assets acquired are accounts receivable of \$9.1 million. The receivables are joint venture and trade receivables for which the fair value approximates carrying value.

The settlement of a pre-existing relationship related to an outstanding payable balance between Verano and the Company that was no longer owed as a result of the Acquisition.

The pro forma results for period ended December 31, 2014 are shown below, as if the Verano Acquisition had occurred on January 1, 2014. Pro forma results are not indicative of actual results or future performance.

Oil sales	\$	115,889
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The consolidated statement of comprehensive income (loss) for the period ended December 31, 2014 includes \$78.3 million of oil sales attributable to the assets acquired since the Verano Acquisition. Revenue less direct costs for the period ended December 31, 2014 attributable to the assets acquired since the Verano Acquisition is \$44.8 million. The pro forma net income and pro forma net income per share, basic and diluted, are considered impracticable to calculate and therefore not included. Pro forma results are not indicative of actual results or future performance.

b) Sorigenia Acquisition

On April 7, 2014, Parex, through a foreign subsidiary, acquired Sorigenia E&P Colombia BV ("Sorigenia") which assets primarily consist of interests in four exploration blocks located in Colombia's Llanos Basin (the "Sorigenia Acquisition"). The Sorigenia acquisition consolidates the Company's interests in Blocks LLA-24 and LLA-26 to 100%. In addition, the Company acquired an additional 25% working interest in the Cerrero Block and 10% working interest in the Balay development area. Total net consideration paid was \$4.8 million in cash.

The consolidated statement of comprehensive income (loss) includes the results of operation of Sorigenia since the closing date of April 7, 2014. This transaction has been accounted for using the acquisition method whereby the assets acquired and the liabilities assumed are recorded at fair values. As the fair value of the identifiable assets was determined to equal the purchase price, no goodwill arose on the transaction. The following table summarizes the recognizable assets acquired and consideration paid pursuant to the acquisition:

Assets acquired and liabilities assumed⁽¹⁾

Working capital surplus	\$	7
E&E assets		5,218
Decommissioning and environmental liabilities		(394)
	\$	4,831

⁽¹⁾ The above amounts are estimates, which were made by management at the time of the preparation of these financial statements based on information then available. Amendments may be made to these amounts as values subject to estimate are finalized.

Consideration for the acquisition

Cash paid	\$	5,000
Cash acquired		(169)
Total net consideration paid	\$	4,831

Included in the working capital surplus of assets acquired are accounts receivable of \$0.4 million. The receivables are joint venture and trade receivables for which the fair value approximates carrying value.

The consolidated statement of comprehensive income (loss) for the period ended December 31, 2014 includes \$1.0 million in oil sales attributable to the assets acquired since the Sorgenia Acquisition. Revenue less direct costs for the period ended December 31, 2014 attributable to the assets acquired since the Sorgenia Acquisition is \$0.6 million. As there was no production from the assets purchased prior to the Acquisition date, pro forma revenue for the period ended December 31, 2014, as if the Sorgenia Acquisition had occurred on January 1, 2014, are the same as actual. Pro forma net income and pro forma net income per share, basic and diluted, are considered impracticable to calculate and therefore not included. Pro forma results are not indicative of actual results or future performance.

Summary of Quarterly Results (Unaudited)

Three months ended (\$000s)	Dec. 31, 2014	Sep. 30, 2014	June 30, 2014	March 31, 2014
Average daily oil production (bopd)	26,544	25,175	19,876	18,425
Realized sales price - oil (\$/bbl)	60.08	94.40	104.53	103.42
Financial (000s except per share amounts)				
Oil and gas sales	\$ 160,584	\$ 228,648	\$ 182,996	\$ 179,794
Funds flow from continuing operations ⁽¹⁾	\$ 49,759	\$ 89,006	\$ 77,799	\$ 77,289
Per share – basic	0.37	0.70	0.70	0.71
Per share – diluted	0.37	0.69	0.65	0.65
Adjusted net income (loss) ⁽¹⁾⁽³⁾	\$ (50,996)	\$ 16,768	\$ 24,679	\$ 20,099
Per share – basic	(0.38)	0.13	0.22	0.18
Per share – diluted	(0.38)	0.13	0.20	0.17
Net income (loss)	\$ (146,612)	\$ 16,768	\$ 11,408	\$ 9,663
Per share – basic	(1.09)	0.13	0.10	0.09
Per share – diluted	(1.09)	0.13	0.10	0.09
Capital Expenditures, excluding corporate acquisitions	\$ 83,571	\$ 56,799	\$ 95,101	\$ 61,405
Total assets (end of period)	\$ 1,034,415	\$ 1,266,610	\$ 1,226,983	\$ 882,306
Working capital surplus (deficit) (end of period) ⁽²⁾	\$ 3,261	\$ 45,321	\$ 31,189	\$ 36,957
Debentures (end of period) ⁽⁴⁾	\$ -	\$ -	\$ 68,375	\$ 64,728
Bank debt (end of period)	\$ 35,000	\$ 42,305	\$ 56,000	\$ 4,000

⁽¹⁾ Non-GAAP term. See “Non-GAAP Terms” below.

⁽²⁾ The December 31, 2014 working capital surplus does not include the undrawn \$140.0 million available from the credit facility.

⁽³⁾ Net income has been adjusted for the IFRS accounting effects of changes in the derivative financial liability and the non-cash impairments recorded.

⁽⁴⁾ During August and September 2014, the Cdn\$85.0 million principal amount of Debentures were converted for an aggregate of 8,339,991 common shares of the Company and redeemed for \$0.3 million in cash.

Three months ended (\$000s)	Dec. 31, 2013	Sep. 30, 2013	June 30, 2013	March 31, 2013
Average daily oil production (bopd)	17,287	16,199	15,463	14,440
Realized sales price - oil (\$/bbl)	101.64	106.41	99.34	109.63
Financial (000s except per share amounts)				
Oil and gas sales	\$ 166,959	\$ 157,043	\$ 147,585	\$ 164,990
Funds flow from continuing operations ⁽¹⁾	\$ 76,304	\$ 68,763	\$ 65,893	\$ 60,710
Per share – basic	0.70	0.64	0.61	0.56
Per share – diluted	0.62	0.56	0.52	0.48
Adjusted net income (loss) ⁽¹⁾⁽³⁾	\$ 23,201	\$ (23,940)	\$ 5,987	\$ 6,539
Per share – basic	0.21	(0.22)	0.06	0.06
Per share – diluted	0.19	(0.22)	0.05	0.05
Net income (loss)	\$ 21,869	\$ (27,965)	\$ 7,632	\$ 11,136
Per share – basic	0.20	(0.26)	0.07	0.10
Per share – diluted	0.18	(0.26)	0.04	0.05
Capital Expenditures, excluding corporate acquisitions	\$ 58,817	\$ 49,962	\$ 77,921	\$ 47,172
Total assets (end of period)	\$ 854,808	\$ 820,827	\$ 824,276	\$ 827,821
Working capital surplus (deficit) (end of period) ⁽²⁾	\$ 24,005	\$ 18,801	\$ 8,630	\$ 16,972
Debentures (end of period) ⁽⁴⁾	\$ 66,060	\$ 66,898	\$ 64,338	\$ 65,402
Bank debt (end of period)	\$ 8,530	\$ 18,500	\$ 27,400	\$ 20,000

⁽¹⁾ Non-GAAP term. See “Non-GAAP Terms” below.

⁽²⁾ The December 31, 2013 working capital surplus does not include the undrawn \$91.5 million available from the credit facility.

⁽³⁾ Net income has been adjusted for the IFRS accounting effects of changes in the derivative financial liability.

⁽⁴⁾ During August and September 2014, the Cdn\$85.0 million principal amount of Debentures was converted for an aggregate of 8,339,991 common shares of the Company and redeemed for \$0.3 million in cash.

Factors that Caused Variations Over the Quarters

Throughout 2014 Parex grew production resulting in increased funds flow from operations quarter over quarter until the fourth quarter where the rapid decline in oil prices resulted in lower funds flow from the previous quarter notwithstanding an increase in production. In the fourth quarter of 2014 the Company recorded a \$20.0 million non-cash impairment relating to the sale of its Trinidad and Tobago subsidiary, a \$44.3 million non-cash impairment on exploration and evaluation assets in Colombia, and a \$113.3 million non-cash impairment on property, plant and equipment in Colombia, resulting in a net loss of \$146.6 million for the quarter (Refer to the “Non-cash Impairment Charges” section for additional information).

In the second quarter of 2014 the Company completed an acquisition of Verano Energy Limited. The acquisition was partially funded through the Company’s working capital and bank facility resulting in a significant increase in bank debt from the first quarter to the second quarter of 2014. Net debt at June 30, 2014 of \$110.5 million was reduced to \$31.7 million at December 31, 2014 primarily as a result of the redemption of the Company’s Debenture in the third quarter of 2014.

Working capital and bank debt fluctuations quarter over quarter are mainly a result of the difference between funds flow from operations in the quarter and capital expenditures incurred in the period. Funds flow from operations fluctuate due mainly to inventory movements, world oil prices and operating netback items including production and transportation expenses.

Please refer to “Financial and Operating Results” for detailed discussions on variations during the comparative quarters and to Parex’ previously issued interim and annual MD&A for changes in prior quarters.

Fourth Quarter Results (Unaudited)

An unaudited income statement for the three months ended December 31 is set out below:

(\$000s)				
For the three month period ended December 31,			2014	2013
Oil and gas sales	\$	160,584	\$	166,959
Royalties		(16,186)		(18,745)
Revenue		144,398		148,214
Risk management contracts		6,232		(2,146)
		150,630		146,068
Expenses				
Production		26,699		15,881
Transportation		46,191		30,663
Purchased oil		12,462		3,297
General and administrative		8,925		7,680
Share-based compensation		(3,079)		2,481
Depletion, depreciation and amortization		51,665		55,290
Foreign exchange gain		(7,261)		(2,564)
Exploration and evaluation impairment		44,387		-
PP&E Impairment		113,264		-
Loss (gain) on settlement on decommissioning liabilities		7		(419)
		293,260		112,309
Finance income		79		62
Finance expense		3,958		7,345
Net finance expense		4,037		7,407
Income (loss) from continuing operations before income taxes		(146,667)		25,352
Income tax expense				
Current tax expense		7,368		10,692
Deferred tax recovery		(28,022)		(7,025)
		(20,654)		3,667
Net income (loss) and comprehensive income (loss) from continuing operations after income taxes	\$	(126,013)	\$	22,685
Loss from discontinued operations after income taxes		(20,599)		(816)
Net income (loss) and comprehensive income (loss) for the period	\$	(146,612)	\$	21,869

Liquidity and Capital Resources

At December 31, 2014, the Company had a working capital surplus of \$3.3 million including \$39 million of cash, excluding amounts available under the credit facility, as compared to working capital surplus at September 30, 2014 of \$45.3 million and a working capital surplus at December 31, 2013 of \$24 million. Bank debt was \$35 million compared to \$8.5 million at December 31, 2013. The credit facility has a current borrowing base of \$175 million. Combined working capital net of bank debt and the USD Notional Principal face value of the Debenture of \$85.6 million has improved from December 31, 2013 to December 31, 2014 by \$38.5 million, which is mainly a function of the Company redeeming the Debenture in the period. At December 31, 2014 Parex held \$39 million of cash, compared to \$56.5 million at December 31, 2013. The Company's cash balances reside in current accounts, the majority of which are held on account in Canada, Barbados and Colombia.

The Company values its crude oil inventory on hand using weighted average cost for the inventoried barrels. At December 31, 2014, on a fair market value basis the inventory on hand would have a value of approximately \$13.4 million or a positive fair value adjustment of approximately \$2.4 million (December 31, 2013 - value of \$15.0 million or a fair value adjustment of \$6.3 million).

Parex has a \$200 million senior secured credit facility ("credit facility") with a syndicate of banks led by a major Canadian bank, with a current borrowing base of \$175 million. Key covenants include a current ratio test of 1:1 adjusted for undrawn amounts on the facility plus the fair value of inventoried oil, and a rolling four quarters total funded debt to EBITDA test of 3.5:1, and other standard business operating covenants. As at December 31, 2014, the Company is in compliance with all covenants. Further, the Company has received notification that the borrowing base will be increased to \$200 million as a result of the

significant increase in producing reserves from the last borrowing base review. The Company is currently finalizing documentation with the bank syndicate regarding the borrowing base increase.

Debentures

On August 12, 2014 the Company issued a notice of redemption to holders of its then outstanding Cdn\$85.0 million Convertible Debentures (the “Debentures”), with the redemption date set as September 24, 2014. The Debentures had a face value of \$1,000 per debenture, and were convertible into common shares at the option of the holder at a conversion price of Cdn\$10.15 per share representing a conversion rate of approximately 98.52 common shares per Debenture. Parex had the right to redeem the Debenture at par anytime after July 1, 2014 if the volume weighted average price of a common share of the Company was in excess of 125% of the conversion price. During August and September 2014, the Cdn\$85.0 million principal amount of Debentures was converted for an aggregate of 8,339,991 common shares of the Company and redeemed for \$0.3 million in cash. The annual coupon on the debentures was 5.25 percent paid semi-annually in arrears on June 30 and December 31 of each year. The holders of the debentures received accrued and unpaid interest for the period from July 1, 2014 to the date of conversion. A gain of \$0.6 million on the settlement of the Debentures and the related derivative financial liability was recognized in the consolidated statement of comprehensive income (loss) during the period ended December 31, 2014.

The following table summarizes the accounting for the debentures:

		Liability	Derivative financial liability	Total
Balance, December 31, 2012	\$	65,657	\$ 9,899	\$ 75,556
Accretion		4,163	-	4,163
Amortization of debt issuance costs		627	-	627
Derivative gain		-	(885)	(885)
Foreign exchange gain		(4,387)	(639)	(5,026)
Balance, December 31, 2013	\$	66,060	\$ 8,375	\$ 74,435
Accretion		3,210		3,210
Amortization of debt issuance costs		475		475
Derivative loss		-	23,707	23,707
Foreign exchange gain		(3,596)	(27)	(3,623)
Debentures converted or redeemed		(66,149)	(32,055)	(98,204)
Balance at December 31, 2014	\$	-	\$ -	\$ -

The accretion, interest paid, amortization of Debenture issuance costs, derivative loss and gain on the settlement of the Debenture are charged to finance expense in the consolidated statement of comprehensive income (loss). Prior to the settlement of the Debenture, the derivative financial liability was measured at fair value through profit or loss using the Black-Scholes valuation model, with the non-cash changes to the fair value of \$23.7 million being recorded to finance expense.

In association with the settlement of the Debenture, the Cross Currency Interest Rate Swap has also been terminated in the current period (Refer to the “Risk Management” section for additional information).

Outstanding Share Data

Parex is authorized to issue an unlimited number of voting common shares without nominal or par value. As at December 31, 2014 the Company had 134,689,938 common shares outstanding.

The Company has a stock option and RSU plan. The plans provide for the issuance of options to the Company’s directors, officers and certain employees to acquire common shares. The maximum number of options and RSU’s reserved for issuance under the two plans may not exceed 10 percent of the number of common shares issued and outstanding.

As at March 10, 2015 Parex has the following securities outstanding:

	Number	%
Common shares	134,759,403	94
Stock options	7,591,844	5
Restricted share units	1,646,586	1
	143,997,833	100

As of the date of this MD&A, total stock options and RSU's outstanding represent approximately 7 percent of the total issued and outstanding common shares.

Contractual Obligations, Commitments and Guarantees

In the normal course of business, Parex has entered into arrangements and incurred obligations that will affect the Company's future operations and liquidity. These commitments primarily relate to exploration work commitments including seismic and drilling activities. The Company has discretion regarding the timing of capital spending for exploration work commitments, provided that the work is completed by the end of the exploration periods specified in the contracts or the Company can negotiate extensions of the exploration periods. The Company's exploration commitments are described in the Company's AIF dated March 19, 2014. The Company's exploration commitments are described under "Description of Business - Principal Properties". These obligations and commitments are considered in assessing cash requirements in the discussion of future liquidity.

In Colombia, the Company has provided guarantees to the Colombian energy regulator ("ANH") which on December 31, 2014 were \$103.4 million (December 31, 2013 - \$32.7 million) to support the exploration work commitments on its blocks. The guarantees have been provided in the form of letters of credit for varying terms. Export Development Canada ("EDC") has provided performance security guarantees to support approximately 71 percent of the letters of credit issued on behalf of Parex. The letters of credit issued to the ANH are reduced from time to time to reflect the work performed on the various blocks.

The following table summarizes the Company's estimated commitments as at December 31, 2014:

(\$000s)		Total		<1 year		1 – 3 years		3 – 4 years		>5 years
Exploration ⁽¹⁾	\$	185,380	\$	47,985	\$	137,395	\$	-	\$	-
Office and accommodations ⁽²⁾		6,714		2,202		2,555		1,957		-
Decommissioning expenditures		50,940		2,791		5,856		5,581		36,712
Total	\$	243,034	\$	52,978	\$	145,806	\$	7,538	\$	36,712

⁽¹⁾ Exploration commitments do not include production bonuses and other payments that will vary depending on production levels due to the uncertainty of their amount and timing.

⁽²⁾ Includes minimum lease payment obligations associated with leases for office space and accommodations.

Non-cash Impairment Charges

(\$000s)			For the three months ended December 31, 2014	2013		For the year ended December 31, 2014	2013
Impairment of PP&E related to Northern Llanos CGU	\$	113,264	\$	-	\$	113,264	\$ -
Impairment of Block LLA-40 E&E assets on transfer to PP&E		23,637		-		23,637	-
Impairment of Block LLA-29 E&E assets		20,750		-		20,750	-
Impairment of E&E assets included in discontinued operations		19,633		687		19,633	38,305
Total non-cash impairment charges before deferred income tax recoveries	\$	177,284	\$	687	\$	177,284	\$ 38,305

At December 31, 2014, the Company determined that the carrying amount of the Northern Llanos Basin CGU exceeded its recoverable amount. A loss of \$113.3 million was recorded as impairment of property, plant and equipment in the consolidated statement of comprehensive income (loss). Future cash flows for the CGU declined due to lower crude oil prices, there were no negative reserve report revisions or cost structure changes.

The recoverable amount was determined using fair value less costs of disposal. The fair value for producing properties was calculated based on discounted after-tax cash flows of proved and probable reserves using forecast prices and cost estimates, consistent with the Company's independent qualified reserves

evaluators (level 3 inputs). There are no E&E assets associated with this CGU. Future cash flows were discounted using a rate of 11 percent. As at December 31, 2014, the recoverable amount as calculated of the Northern Llanos CGU was estimated to be \$61.7 million.

The Company also completed an impairment review for certain E&E assets associated with Block LLA-40 in the Northern Llanos CGU prior to its transfer to PP&E. Block LLA-40 is an acquired Block that required 4 commitment wells to be drilled. Of the four wells drilled, two were dry and abandoned, and two are producing wells. It was determined that the carrying amount of the project assets was unlikely to be recovered by successful development or sale. The impairment review compared the carrying value of the assets to the recoverable amount. The recoverable amount was calculated based on discounted after-tax cash flows of proved and probable reserves using forecast prices and cost estimates, consistent with the Company's independent qualified reserves evaluators (level 3 inputs). It was determined that the impairment was \$23.6 million which is recorded in the consolidated statement of comprehensive income (loss) for the year ended December 31, 2014. The recoverable amount was determined to be \$5.9 million using an after-tax discount rate of eleven percent, and was subsequently transferred to property, plant and equipment.

The Company also completed an impairment review for certain E&E assets located in Block LLA-29 in the Llanos basin in the fourth quarter of 2014 due to extended community problems that have forced the block into force majeure. The Block has no producing assets and one dry hole has been drilled on the Block to date. The impairment review compared the carrying value of assets to the recoverable amount. It was determined that the impairment was \$20.8 million which is recorded in the consolidated statement of comprehensive income (loss) for the year ended December 31, 2014. The recoverable amount was determined to be \$nil as there is no certainty the block can be accessed in a normal course manner.

During the fourth quarter of 2014, the Company entered into negotiations with a third party to purchase from the Company all of the issued and outstanding shares in the capital of Parex Resources (Trinidad) Ltd. Associated with this, the Company completed an impairment review of the exploration and evaluation assets in Trinidad & Tobago. The impairment review compared the carrying value of the assets to the recoverable amount. The recoverable amount was estimated using fair value less costs of disposal based on the above noted indications from third parties in the Company's interest in the assets. It was determined that the impairment was \$19.6 million which is recorded in the consolidated statement of comprehensive income (loss) for the year ended December 31, 2014 as part of discontinued operations. The recoverable amount of the assets was determined to be \$1.9 million, net of associated decommissioning liabilities of \$0.4 million, and was transferred to assets held for sale.

Overall the impairments resulted in a reduction in net income before tax of \$177.3 million (\$115.2 million after deferred tax recoveries) resulting in a net loss being recorded for the year.

Impairment Test of Goodwill

The Company performed its annual test for goodwill impairment at the balance sheet date in accordance with its policy described in note 3 of the consolidated financial statements. The Company has allocated goodwill to the Colombia operating segment.

Notwithstanding the impairments discussed above, the estimated fair value less costs of disposal of the Colombia operating segment exceeded the carrying value. As a result, no goodwill impairment was recorded.

Valuation Techniques

The recoverable amount of the group of CGUs in which the goodwill was assigned is based on fair value less costs of disposal. The technique used in determining the recoverable amount is based on the net present value of the after-tax cash flows from oil and gas reserves of the group of CGU's based on reserves estimated by Parex' independent reserve evaluator and the fair value of undeveloped land based on estimates with consideration given to acquisition metrics of recent transactions completed on similar assets to those contained within the relevant group of CGU's. The discounting process uses a rate of return that is commensurate with the risk associated with the assets and the time value of money. This approach requires assumptions about revenue, future oil prices, tax rates and discount rates, all of which are level 3 inputs.

Significant Assumptions

Oil Reserves

Assumptions that are valid at the time of reserve estimation may change significantly when new information becomes available. Changes in forward price estimates, production costs or recovery rates may change the economic status of reserves and may ultimately result in reserves being restated.

Future Oil Prices

Oil forward price estimates are used in the cash flow model. Commodity prices have fluctuated widely in recent years due to global and regional factors including supply and demand fundamentals, inventory levels, exchange rates, weather, economic and geopolitical factors. The future oil prices used in the model are based on a forecast of crude oil prices by Parex' independent reserve evaluator. Prices used are as follows:

	2015	2016	2017	2018	2019	Thereafter
Brent (\$US/bbl)	67.50	82.50	87.50	90.00	95.00	2% increase per year

Discount Rate

The Company assumed a discount rate in order to calculate the present value of its projected cash flows. The discount rate represented a weighted average cost of capital ("WACC") for comparable companies operating in similar industries, based on publicly available information. The WACC is an estimate of the overall required rate of return on an investment for both debt and equity owners and serves as the basis for developing an appropriate discount rate. Its determination requires separate analysis of the cost of equity and debt, and considers a risk premium based on an assessment of risks related to the projected cash flows of the group of Colombia CGU's. The discount rate used in performing the impairment test was 11 percent.

The fair value of the group of Colombian CGU's was in excess of its carrying value. Based on sensitivity analysis, no reasonably possible change in discount rate assumptions would cause the carrying amount of the group of Colombia CGUs to exceed its recoverable amount.

Decommissioning and Environmental Liabilities

	Decommissioning		Environmental		Total
Balance, December 31, 2012	\$	12,079	\$	-	\$ 12,079
Additions		5,140		3,017	8,157
Property acquisition		809		-	809
Settlements of obligations during the year		(1,400)		-	(1,400)
Gain on settlements of obligations during the year		(712)		-	(712)
Change in estimates		(2,570)		4,144	1,574
Accretion expense		447		134	581
Balance, December 31, 2013	\$	13,793	\$	7,295	\$ 21,088
Additions		9,479		3,201	12,680
Corporate acquisitions		1,300		946	2,246
Settlements of obligations during the year		(1,369)		(425)	(1,794)
Loss on settlements of obligations during the year		134		-	134
Accretion expense		864		263	1,127
Additions related to change in estimate		-		657	657
Foreign exchange gain		-		(1,660)	(1,660)
Balance, December 31, 2014	\$	24,201	\$	10,277	\$ 34,478
Current obligation		-		(2,143)	(2,143)
Decommissioning liabilities reclassified to liabilities held for sale		(389)		-	(389)
Long-term obligation	\$	23,812	\$	8,134	\$ 31,946

The total environmental, decommissioning and restoration obligations were determined by management based on the estimated costs to settle environmental impact obligations incurred and to reclaim and abandon the wells and well sites based on contractual requirements. The obligations are expected to be funded from the Company's internal resources available at the time of settlement.

The total decommissioning and environmental liability is estimated based on the Company's net ownership in wells drilled as at December 31, 2014, the estimated costs to abandon and reclaim the wells and well sites and the estimated timing of the costs to be paid in future periods. The total undiscounted amount of cash flows required to settle the Company's decommissioning liability is approximately \$37.0 million as at December 31, 2014 (December 31, 2013 – \$19.4 million) with the majority of these costs anticipated to occur in 2020 or later. A weighted average risk-free discount rate of 5% and an inflation rate of 2% were used in the valuation of the liabilities (December 31, 2013 – 5% weighted average risk-free discount rate and a 2% inflation rate). The discount rates used are a blend of US and Colombia risk-free rates.

The total undiscounted amount of cash flows required to settle the Company's environmental liability is approximately \$14.0 as at December 31, 2014 (December 31, 2013 – \$8.4 million) with the majority of these costs anticipated to occur in 2015 or later in Colombia. A risk-free discount rate of 7% and an inflation rate of 3% were used in the valuation of the liabilities (December 31, 2013 – 6% risk-free discount rate and a 3% inflation rate). The discount rate used is based on a Colombia risk-free rate.

Included in the environmental liability is \$2.1 million (December 31, 2013 – \$1.6 million) that is classified as a current obligation.

Decommissioning and environmental liabilities are considered critical accounting estimates. There are significant uncertainties related to decommissioning and environmental expenditures and the impact on the financial statements could be material. The eventual timing of and costs for these expenditures could differ from current estimates. The main factors that can cause expected estimated cash flows in respect of decommissioning liabilities to change are:

- Changes in laws, legislation and regulations;
- Construction of new facilities;
- Change in commodity price;
- Change in the estimate of oil reserves and the resulting amendment to the life of reserves; and,
- Changes in technology.

Reserves Information

The reserves information summarized in this MD&A is from reports prepared by our independent reserves evaluator, GLJ Petroleum Consultants Ltd. ("GLJ"), dated February 4, 2015 with an effective date of December 31, 2014, and dated February 4, 2014 with an effective date of December 31, 2013. Each of these reports was prepared in accordance with definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook and National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). All December 31, 2014 reserves presented are based on GLJ's forecast pricing effective January 1, 2015 and all December 31, 2013 reserves presented are based on GLJ's forecast pricing effective January 1, 2014. Additional reserve information as required under NI 51-101 will be included in the Company's Annual Information Form which will be filed on SEDAR by March 31, 2015.

Advisory on Forward-Looking Statements

Certain information regarding Parex set forth in this MD&A, including assessments by the Company's management of the Company's plans and future operations, contains forward-looking statements that involve substantial known and unknown risks and uncertainties. The use of any of the words "plan", "expect", "forecast", "project", "intend", "believe", "anticipate", "estimate" or other similar words, or statements that certain events or conditions "may" or "will" occur are intended to identify forward-looking statements. Such statements represent the Company's internal projections, estimates or beliefs concerning, among other things, future growth, results of operations, production, future capital and other expenditures (including the amount, nature and sources of funding thereof), competitive advantages, plans for and results of drilling activity, environmental matters, business prospects and opportunities. These statements are only predictions and actual events or results may differ materially. Although the Company's management believes that the expectations reflected in the forward-looking statements are reasonable, it cannot guarantee future results, levels of activity, performance or achievement since such expectations are inherently subject to significant business, economic, competitive, political and social uncertainties and contingencies. Many factors could cause the Company's actual results to differ materially from those expressed or implied in any forward-looking statements made by, or on behalf of, Parex. In particular, forward-looking statements contained in this MD&A include, but are not limited to, statements with respect to:

- the Company's operational strategy, including targeted jurisdictions and technologies used to execute its strategy;
- the Company's approach to manage subsurface and commercial risks;
- the Company's exploration blocks subject to farm-in and earning requirements;
- activities to be undertaken in various areas including the fulfillment of exploration commitments and farm-in obligations;
- terms of exploration and production contracts and the timing of release of exploration property deemed non-commercial in respect of the exploration contracts;
- the Company's planned range of capital expenditures for 2015, along with the focus and timing thereof and the method of funding;
- the Company's forecast average production range for 2015;
- the Company's expectations that its realized price will become less dependent upon timing of crude shipments and sales;
- the status of the Company's review of transportation and marketing alternatives in an effort to maximize the net proceeds from production in Colombia;
- expected royalty rates as a percentage of sales and effect of changes in pricing on the Company's overall royalty as a percentage of sales;
- the Company's expectations in respect of reductions in production costs due to the depreciation of the Colombian peso;

- the Company's expectation that the Tigana and Tua fields will become subject to the High Price Share in the second quarter of 2015;
- expected transportation costs (including trucking costs) on a per barrel basis, and the effect of depreciation of the Colombian peso and increased pipeline capacity on pipeline tariffs;
- terms of stock based compensation plans, including option plan, restricted share unit plan, and share appreciation rights;
- foreign currency risk and the ability to reverse unrealized foreign exchange gains and losses in the future;
- expectations regarding the effect of conversion and redemption of the Debentures on foreign exchange adjustments;
- the Company's expectations as to future foreign exchange adjustments;
- the Company's risk management strategy, terms of the Company's risk management contracts and the anticipated effect of derivative contracts on managing cash flow;
- estimated income tax expense and expected effective Colombian corporate income tax rate for the year ended December 31, 2014;
- estimated recoverable amount of the Northern Llanos CGU and certain E&E assets at December 31, 2014;
- terms of the Company's credit facility and the Company's expectation that the borrowing base will be increased as a result of significant increases in the Company's producing reserves;
- terms of the Company's NCIB;
- terms of the Company's exploration and other contractual commitments;
- the anticipated sources of funding for the Company's environmental, decommissioning and restoration obligations;
- impact of new and revised accounting pronouncements and critical accounting estimates; and
- effect of business and environmental risks on the Company.

These forward-looking statements are subject to numerous risks and uncertainties, including but not limited to: the impact of general economic conditions in Canada and Colombia; industry conditions including changes in laws and regulations including adoption of new environmental laws and regulations, and changes in how they are interpreted and enforced in Canada and Colombia; competition; lack of availability of qualified personnel; the results of exploration and development drilling and related activities; partner approval of capital work programs and other matters requiring approval; imprecision in reserve and resource estimates; the production and growth potential of Parex' assets; obtaining required approvals of regulatory authorities in Canada and Colombia; risks associated with negotiating with foreign governments as well as country risk associated with conducting international activities; volatility in market prices for oil and natural gas; fluctuations in foreign exchange or interest rates; environmental risks; community and social issues; changes in income tax laws, royalty or fiscal regimes, or changes in tax laws and incentive programs relating to the oil and natural gas industry; ability to access sufficient capital from internal and external sources; risk that the Company will not be able to obtain contract extensions or fulfill the contractual obligations required to retain its rights to explore, develop and exploit any of its undeveloped properties; risk of failure to achieve the anticipated benefits associated with the acquisitions of Verano and Sorigenia; risks related to the lawsuit brought in Texas against Parex and certain foreign subsidiaries; failure of counterparties to perform under the terms of their contracts; the risks discussed under "Risk Factors" in the Company's Annual Information Form dated March 19, 2014 and under "Business Environment and Risks" in this MD&A, and other factors, many of which are beyond the control of the Company. Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect the Company's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com).

Although the forward-looking statements contained in this MD&A are based upon assumptions which management believes to be reasonable, the Company cannot assure investors that actual results will be consistent with these forward-looking statements. With respect to forward-looking statements contained in this MD&A, Parex has made assumptions regarding, among other things: current commodity prices and royalty regimes; availability of skilled labour; timing and amount of capital expenditures; uninterrupted access to areas of the Company's operations and infrastructure; future exchange rates; the price of oil; the impact of increasing competition; conditions in general economic and financial markets; availability of drilling and related equipment; effects of regulation by governmental agencies; recoverability of reserves and future production rates; royalty rates; future operating costs; foreign exchange rates; the status of litigation; timing of drilling and completion of wells; that the Company will have sufficient cash flow, debt or equity sources or other financial resources required to fund its capital and operating expenditures and requirements as needed; that the Company's conduct and results of operations will be consistent with its expectations; that the Company will have the ability to develop the Company's oil and gas properties in the manner currently contemplated; current or, where applicable, proposed industry conditions, laws and regulations will continue in effect or as anticipated as described herein; that the estimates of the Company's reserves volumes and the assumptions related thereto (including commodity prices and development costs) are accurate in all material respects; that the Company will be able to obtain contract extensions or fulfill the contractual obligations required to retain its rights to explore, develop and exploit any

of its undeveloped properties; and other matters. The ability of the Company to carry out its business plan is primarily dependent upon the continued support of its shareholders, the discovery of economically recoverable reserves and the ability of the Company to obtain financing to develop such reserves.

Forward-looking statements and other information contained in this MD&A concerning the oil and natural gas industry in the countries in which it operates and the Company's general expectations concerning this industry are based on estimates prepared by Management using data from publicly available industry sources as well as from resource reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which the Company believes to be reasonable. However, these data are inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Company is not aware of any material misstatements regarding any industry data presented herein, the oil and natural gas industry involves numerous risks and uncertainties and is subject to change based on various factors.

Management has included the above summary of assumptions and risks related to forward-looking information provided in this MD&A in order to provide shareholders with a more complete perspective on the Company's current and future operations and such information may not be appropriate for other purposes. The Company's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do, what benefits Parex will derive there from. These forward-looking statements are made as of the date of this MD&A and Parex disclaims any intent or obligation to update publicly any forward-looking statements, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws.

Non-GAAP Terms

This report contains financial terms that are not considered measures under GAAP such as funds flow used in, or from operations, working capital, operating netback per barrel and adjusted net income, but do not have any standardized meaning under IFRS and may not be comparable to similar measures presented by other companies. Management uses these non-GAAP measures for its own performance measurement and to provide shareholders and investors with additional measurements of the Company's efficiency and its ability to fund a portion of its future capital expenditures.

Funds flow from operations is a non-GAAP term that includes all cash generated from operating activities and is calculated before changes in non-cash working capital. Management uses funds from (used in) operations to analyze operating performance and monitor financial leverage, and considers funds 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. Funds flow from operations is reconciled with net (loss) income in the consolidated statements of cash flows. The following table reconciles funds flow from operations to cash flow from operations:

(\$000s)	For the three months ended December 31,		For the year ended December 31,	
	2014	2013	2014	2013
Cash flow from continuing operating activities (GAAP)	\$ 121,457	\$ 25,610	\$ 250,828	\$ 210,296
Changes in non-cash working capital including taxes and interest payable	(71,698)	50,694	43,025	61,374
Funds flow from continuing operations (Non-GAAP)	\$ 49,759	\$ 76,304	\$ 293,853	\$ 271,670

Funds flow per share is calculated by dividing funds flow from operations by the weighted average number of shares outstanding. Parex presents funds 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 shows the variables used in the calculation of diluted funds flow from operations per share:

(\$000s)	For the three months ended December 31,		For the year ended December 31,	
	2014	2013	2014	2013
Funds flow from continuing operations				
Funds flow from continuing operations for the purpose of basic funds flow	\$ 49,759	\$ 76,304	\$ 293,853	\$ 271,670
Debt interest expense	-	1,062	2,948	4,333
Funds flow from continuing operations for diluted funds flow	\$ 49,759	\$ 77,366	\$ 296,801	\$ 276,003
Weighted average number of shares for the purposes of basic funds flow	134,503	108,460	120,379	108,421
(\$000s)				
Dilutive effect of share options on potential common shares	1,637	1,724	2,065	1,134
Dilutive effect of Debentures on potential common shares ⁽¹⁾	-	13,980	-	13,980
Weighted average number of shares for the purposes of diluted funds	\$ 136,140	\$ 124,164	\$ 122,444	\$ 123,535

⁽¹⁾ For the three months and year ended December 31, 2014 the effect of the Debenture is antidilutive.

Adjusted net (loss) income is determined by adding back any unrealized losses or deducting any unrealized gains associated with the Company's derivative financial liability and adding back any non-cash impairments recorded on PP&E and E&E assets. The Company recorded an adjusted net loss of \$51.0 million (\$0.38 per basic share) for the fourth quarter of 2014 and adjusted net income of \$10.6 million (\$0.09 per basic share) for the full year ended December 31, 2014. This excludes the IFRS accounting effects of a \$23.7 million loss upon the revaluation of the derivative liability associated with the Company's Debentures prior to the early conversion and redemption of the Debentures during the third quarter of 2014. It also excludes the non-cash after tax impairment charges of \$27.1 million of exploration and evaluation assets and \$68.5 million on property, plant and equipment in Colombia. As a result of the significant downturn in the outlook for oil and natural gas prices, the Company wrote down the book value of property, plant and equipment by after tax \$68.5 million and wrote down after tax \$27.1 million of exploration and evaluation assets for the period ended December 31, 2014. These non-cash charges did not affect the company's cash flow from operating activities. The company considers adjusted net income a key measure as it helps evaluate the Company's operating performance. The following table reconciles net (loss) income to adjusted net (loss) income:

(\$000s)	For the three months ended December 31,		For the year ended December 31,	
	2014	2013	2014	2013
Net (loss) income (GAAP)	\$ (146,612)	\$ 21,869	\$ (108,773)	\$ 12,672
Non cash loss (gain) on derivative financial liability	-	1,332	23,707	(885)
Impairment of PP&E related to Northern Llanos CGU ⁽¹⁾	68,524	-	68,524	-
Impairment of Block LLA-40 E&E assets on transfer to PP&E ⁽¹⁾	14,300	-	14,300	-
Impairment of Block LLA-29 E&E assets ⁽¹⁾	12,792	-	12,792	-
Adjusted net (loss) income (Non-GAAP)	\$ (50,996)	\$ 23,201	\$ 10,550	\$ 11,787

⁽¹⁾ Impairments are shown net of tax impact.

Operating netback per barrel is determined by sales revenue excluding risk management contracts, less royalties, production expense and transportation expense, divided by total equivalent sales volume excluding purchased oil volumes. The Company considers operating netbacks to be a key measure as they demonstrate Parex' profitability relative to current commodity prices.

Working capital and Net debt are used to assess efficiency, liquidity and the Company's general financial strength. No IFRS measure is reasonably comparable to working capital and Net debt.

Working capital is determined by current assets less current liabilities but may not include changes in non-cash working capital from one period to the next and does not include any undrawn credit facility amount.

Net debt is determined by working capital less long-term debt and USD face value of the convertible debenture.

Free cash flow is determined by cash flow from operations less capital expenditures.

Business Environment and Risks

Overall

Parex is exposed to a variety of risks including but not limited to operational, financial, competitive, political and environmental risks. As a participant in the oil and natural gas industry, Parex is exposed to operational risks such as: unsuccessful exploration and exploitation activities, the inability to find new reserves that are commercially and economically feasible, premature declines of reservoirs, well blow-outs and other operating hazards, and lack of infrastructure or transportation to access markets and monetize reserves. The Company works to mitigate these risks by employing highly skilled personnel and utilizing available technology. The Company also maintains a corporate insurance program consistent with industry practices to protect against insurable losses.

The Company is exposed to normal financial risks inherent in the oil and natural gas industry including: commodity price risk, exchange rate risk, interest rate risk and credit risk. The Company continuously monitors opportunities to use financial instruments to manage exposure to fluctuations in commodity prices, foreign currency rates and interest rates. Parex operates the majority of its properties and, therefore, has significant control over the timing, direction and costs related to exploration commitments and development opportunities.

Foreign Jurisdictions

Parex is focused on international oil and natural gas activities in Colombia. As such, the Company is subject to political risks such as: changes in policies and regulation related to changes in government, price controls, renegotiation of land tenure agreements, nationalization, changes in tax and royalty regulations, amendments or changes to legal systems, and complex regulatory regimes. The Company focuses its foreign operations in countries where management has prior experience and/or engages local in-country staff as soon as possible. The Company engages local, Canadian and international advisors. The Company may also, from time to time, arrange for insurance to mitigate specific risks. The Company is also exposed to potential delay of its operations due to waiting on permits or obtaining surface access to drilling locations.

Reserves Estimates

Parex has retained an independent engineering consulting firm that assists the Company in evaluating oil and natural gas reserves on an annual basis. Reserve values are based on a number of variables and assumptions such as future commodity prices, projected production, future production costs and governmental regulations. Reserve estimates are prepared in accordance with standards and procedures set out in the Canadian Oil and Gas Evaluation Handbook and National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). The reserves and recovery information contained in the independent reserve report is an estimate. The actual production and ultimate reserves from the properties may be greater or less than the estimates prepared by the independent reserve engineers.

Volatility of Commodity Prices and Foreign Exchange Rates

The Company's operational results and financial condition depend on the prices received for petroleum production. Commodity prices are determined by economic and, in some circumstances, political factors. Supply and demand factors, including weather and general economic conditions as well as conditions in other oil and natural gas regions, also influence prices. Parex is exposed to commodity price risk whereby the fair value of future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for petroleum are affected by the global economic events that dictate the levels of supply and demand. As at the date of this MD&A, Parex has six crude oil hedges in place (see "Risk Management Contracts – Brent Crude").

Foreign currency risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate as a result of changes in foreign currency exchange rates. The Company is exposed to foreign currency fluctuations as various portions of its cash balances and future expenses and revenues are denominated in Colombian pesos (COP\$) and Canadian dollars (Cdn\$). At the date of this MD&A, Parex had two foreign currency exchange risk management contracts in place (see "Risk Management Contracts – Foreign Exchange").

Counterparty Risk

Credit risk is the risk of a counterparty failing to meet its obligations in accordance with the agreed upon terms. The Company may be exposed to third-party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its commodities and other parties. Parex has established credit policies and controls designed to mitigate the risk of default or non-payment with respect to oil and natural gas sales, financial hedging

transactions and joint venture participants. The Company makes every effort to sell its commodities to major companies with excellent credit ratings and/or managing its crude production on a portfolio basis.

Access to Capital

From time to time, the Company may have to raise additional funds to finance business development activities. Parex' ability to raise additional capital will depend on a number of factors such as general economic and market conditions that are beyond the Company's control. Internally generated funds will also fluctuate with changing commodity prices. Parex currently has a \$175 million syndicated facility with three banks. The Company is required to comply with covenants under this facility and in the event it does not comply, access to capital could be restricted or repayment may be required. Parex routinely reviews the covenants based on actual and forecasted results and has the ability to make changes to development and exploration plans to comply with the covenants under the credit facility. Parex is committed to maintaining a strong balance sheet along with an adaptable capital expenditure program that can be adjusted to capitalize on, or reflect acquisition opportunities and, if necessary a tightening of liquidity sources. From the company's founding to the date of this MD&A, Parex has had no defaults or breaches on its bank debt or any of its financial liabilities.

Operational Matters

The oil and natural gas industry is intensely competitive, with Parex competing against companies that may have greater technical and financial resources. There is competition for new exploration and development properties, for infrastructure and sales contracts, for drilling and other specialized technical equipment and for experienced key human resources. As appropriate, Parex seeks to enter into joint venture arrangements with large and/or experienced industry players in each country to improve its access to resources.

There are also extensive and varying environmental regulations imposed by the governments in the countries in which Parex operates. The Company adopts prudent and industry-recommended field operating procedures in all of its operations, as well as maintaining a health, safety and environment program.

Exploration

The Company is exposed to a high level of exploration risk. The Company's current and future (to the extent discovered or acquired) proved reserves will decline as reserves are produced from its properties unless the Company is able to acquire or develop new reserves. The business of exploring for, developing or acquiring reserves is capital-intensive and is subject to numerous estimates and interpretations of geological and geophysical data. There can be no assurance that the Company's future exploration, development and acquisition activities will result in material additions of proved reserves. To manage this risk, to the extent possible, Parex employs highly experienced geologists and geophysicists, uses technology such as 3D seismic as a primary exploration tool and focuses exploration efforts in known hydrocarbon-producing basins. In addition, the Company takes a portfolio approach to exploration by dispersing drilling locations among different exploration blocks and geological basins and by targeting multiple play-types. The Company may also choose to mitigate exploration risk through acquisitions that may require raising funds.

Internal Controls over Financial Reporting

Disclosure controls and procedures ("DC&P"), as defined in National Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*, are designed to provide reasonable assurance that information required to be disclosed in annual filings, interim filings or other reports filed, or submitted by the Company under securities legislation authorities is recorded, processed, summarized and reported within the time periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the Company's management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. The Chief Executive Officer and the Chief Financial Officer of Parex evaluated the effectiveness of the design and operation of the Company's DC&P. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded Parex DC&P were effective as at December 31, 2014.

Internal control over financial reporting ("ICFR"), as defined in National Instrument 52-109, includes those policies and procedures that:

- 1) Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets of Parex;

- 2) Are designed to provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of Parex are being made in accordance with authorizations of management and Directors of Parex; and
- 3) Are designed to provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company's assets that could have a material effect on the annual financial statements or interim financial reports.

The Chief Executive Officer and the Chief Financial Officer are responsible for establishing and maintaining ICFR for Parex. They have, as at the financial year ended December 31, 2014, designed ICFR, or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The control framework Parex officers used to design the Company's ICFR is the Internal Control - Integrated Framework ("COSO Framework") published by The Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Under the supervision of the Chief Executive Officer and the Chief Financial Officer, Parex conducted an evaluation of the effectiveness of the Company's ICFR as at December 31, 2014 based on the COSO Framework. Based on this evaluation, the officers concluded that as of December 31, 2014, Parex maintained effective ICFR. It should be noted that while Parex officers believe that the Company's controls provide a reasonable level of assurance with regard to their effectiveness, they do not expect that the DC&P and ICFR will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, but not absolute, assurance that the objectives of the control system are met.

There were no changes in Parex' ICFR during the year ended December 31, 2014 that materially affected, or are reasonably likely to materially affect, the Company's ICFR.

Off-Balance-Sheet Arrangements

The Company did not enter into any off-balance-sheet arrangements during the twelve months ended December 31, 2014.

Financial Instruments and Other Instruments

The Company's non-derivative financial instruments recognized on the consolidated balance sheet consist of cash, accounts receivable, accounts payable and accrued liabilities, the liability portion of the Debentures, and the long-term debt. Non-derivative financial instruments are recognized initially at fair value. The fair values of the current financial instruments approximate their carrying value due to their short-term maturity.

Accounting Policies and Estimates

The accounting policies set out below have been applied consistently to all years presented in the consolidated financial statements, and have been applied consistently by the Company and its subsidiaries.

a) Consolidation

The consolidated financial statements include the accounts of the Company and all of its subsidiaries at December 31, 2014. The principal operating subsidiaries and their activities are:

Entity	Country of incorporation	Country of principle business activity	Ownership %	Principle business activity
Parex Resources Colombia Ltd.	Barbados	Colombia	100	Oil and natural gas exploration and development
Ramshorn International Limited	Bermuda	Colombia	100	Oil and natural gas exploration and development
Verano Energy Limited S.C.	Barbados	Colombia	100	Oil and natural gas exploration and development
Parex Resources (Trinidad) Ltd.	Trinidad	Trinidad	100	Oil and natural gas exploration and development

The above listing does not include the wholly-owned holding company subsidiaries of Parex. All companies in the Parex group are wholly-owned subsidiaries.

On February 13, 2015, the Company entered into an agreement with a third party in Trinidad to purchase from the Company all of the issued and outstanding shares in the capital of Parex Resources (Trinidad) Ltd. Refer to note 10 – Assets held for sale and discontinued operations.

Inter-company balances and transactions are eliminated on consolidation. Interests in joint arrangements are classified as either joint operations or joint ventures, depending on the rights and obligations of the parties to the arrangement. Joint operations arise when the Company has rights to the assets and obligations for the liabilities of the arrangement. The Company recognizes its share of assets, liabilities, revenues and expenses of a joint operation. A significant portion of the Company's operating cash flows is derived through joint operations which are involved in the development and production of crude oil in Colombia. Joint ventures arise when the Company has rights to the net assets of the arrangement. Joint ventures are accounted for under the equity method.

b) Foreign currency translation

(i) Functional and presentation currency

Items included in the consolidated financial statements are measured using the currency of the primary economic environment in which the Company operates (the "functional currency"). The consolidated financial statements are presented in United States dollars, which is the functional currency of Parex.

(ii) Transactions and balances

Foreign currency transactions are translated into the functional currency using the exchange rates prevailing at the date of the transaction. Generally, foreign exchange gains and losses resulting from the settlement of foreign currency transactions and from the translation at period-end exchange rates of monetary assets and liabilities denominated in currencies other than an operation's functional currency are recognized in the statement of comprehensive income.

c) Financial instruments

The Company initially measures financial instruments at estimated fair value. The Company's loans and receivables, comprised of cash and accounts receivables, are included in current assets due to their short-term nature. Financial liabilities are categorized as "other financial liabilities" consisting of accounts payable and accrued liabilities, the convertible debentures and long-term debt.

Loans and receivables

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market and with no intention of being traded. They are included in current assets, except for maturities greater than 12 months after the balance sheet date, which are classified as non-current assets. Loans and receivables are recognized at the amount expected to be received less any discount or rebate to reduce the loan and receivables to estimated fair value. Loans and receivables are subsequently measured at amortized cost using the effective interest method. For loans and receivables that have maturity dates of less than one year, the Company estimates their carrying value approximates their fair value due to their short-term nature. Loans and receivables are comprised of cash and accounts receivable in the consolidated balance sheet.

Other financial liabilities

Other financial liabilities are financial liabilities that are not quoted on an active market and with no intention of being traded. They are included in current liabilities, except for the convertible debentures and long-term debt as these instruments have maturities greater than 12 months after the balance sheet date and are classified as non-current liabilities. Accounts payable are initially recognized at the amount required to be paid less any discount or rebates to reduce the payables to estimated fair value. Accounts payable are subsequently measured at amortized cost using the effective interest method. For accounts payable that have maturity dates of less than one year, the Company estimates their carrying value approximates their fair value due to their short-term nature. The convertible debentures were recognized initially at fair value, net of any transaction costs incurred, and subsequently at amortized cost using the effective interest rate method.

Derivative instruments

Derivatives may be used by the Company to manage economic exposure to market risk relating to commodity prices, foreign exchange rates and interest rates. Parex' policy is not to utilize derivative financial instruments for speculative purposes. The Company does not designate its financial derivative contracts as hedges, and as such does not apply hedge accounting. As a result, all financial derivative contracts are classified at fair value through comprehensive income (loss) and are recorded on the consolidated balance sheet at fair value.

Financial derivative contracts are initially recognized at fair value on the date a derivative contract is entered into and are remeasured at their fair value at each subsequent reporting date.

Financial derivative instruments are included in current assets (liabilities) except for those with maturities greater than 12 months after the end of the reporting period, which are classified as non-current assets (liabilities).

Convertible Debenture

On issuance, the convertible debenture (“the Debenture”) was split between the financial liability and the equity conversion feature. The Debenture represented a liability in its entirety, as the conversion feature failed the fixed-for-fixed requirement for equity classification as the convertible debenture is denominated in Canadian dollars, whereas the functional currency of Parex is US dollars. Prior to the redemption of the Debenture on September 24, 2014, the convertible feature of the Debenture was required to be fair-valued at each balance sheet date. As a result, the convertible debenture conversion feature was classified at fair value through comprehensive income (loss) and is recorded on the consolidated balance sheet at fair value. Prior to the redemption of the Debenture, the financial liability portion was initially recorded at fair value and accreted to the debenture face value over the term of the Debenture.

d) Capital assets

(i) Exploration and evaluation

All costs directly associated with the exploration and evaluation of oil and natural gas reserves are initially capitalized. E&E costs are those expenditures for an area where technical feasibility and commercial viability have not yet been determined. These costs include unproved property acquisition costs, exploration costs, geological and geophysical costs, decommissioning costs, E&E drilling, sampling and appraisals. Costs incurred prior to acquiring the legal rights to explore an area are charged directly to comprehensive income (loss) as impairment of exploration and evaluation assets.

When an area is determined to be technically feasible and commercially viable the accumulated costs are transferred to PP&E, where they are depleted. When an area is determined not to be technically feasible and commercially viable or the Company decides not to continue with its activity, the unrecoverable costs are charged to comprehensive income (loss) as impairment of exploration and evaluation assets. Net proceeds from any disposal of an intangible exploration asset are recorded as a reduction in intangible assets.

(ii) Property, plant and equipment

All costs directly associated with the development of oil and natural gas reserves are capitalized on an area-by-area basis. Development costs include expenditures for areas where technical feasibility and commercial viability have been determined. These costs include proved property acquisitions, development drilling, completion of wells, gathering facilities and infrastructure, decommissioning and restoration costs and transfers of E&E assets.

Costs accumulated within each CGU are depleted using the unit-of-production method based on proved plus probable reserves incorporating estimated future prices and costs. Costs subject to depletion include estimated future costs to be incurred in developing proved plus probable reserves. Costs of major development projects are excluded from the costs subject to depletion until they are available for use.

Costs associated with office furniture, fixtures and leasehold improvements are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from 1 to 5 years.

e) Impairment of long-term assets

The carrying amounts of the Company’s long-term assets, other than E&E assets and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If an indication of impairment exists, the asset’s recoverable amount is estimated. E&E assets are assessed for impairment when they are reclassified to PP&E, and, if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purpose of impairment testing, assets are grouped into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs of disposal (“FVLCD”).

The value in use is determined by estimating the present value of the pre-tax future net cash flows expected to be derived from the continued use of the asset or CGU. The FVLCD is based on available market information, where applicable. In the absence of such information, FVLCD is determined using discounted future after tax net cash flows of proved plus probable reserves using forecast prices and costs.

E&E assets are allocated to related CGUs where they are assessed for impairment upon their eventual reclassification to PP&E. E&E assets not reclassified to PP&E are assessed for impairment on a block by block basis.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in comprehensive income (loss). Impairment losses recognized in respect of CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the units and then to reduce the carrying amounts of the other assets in the unit (group of units) on a pro-rata basis.

Impairment losses recognized in prior years are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation or amortization, if no impairment loss had been recognized.

f) Assets held for sale

Non-current assets are classified as held for sale if their carrying amounts will be recovered through a sale transaction rather than through continuing use. This condition is met when the sale is highly probable and the asset is available for immediate sale in its present condition. For the sale to be highly probable management must be committed to a plan to sell the asset and an active program to locate a buyer and complete the plan must have been initiated. The asset must be actively marketed for sale at a price that is reasonable in relation to its current fair value and the sale should be expected to be completed within one year from the date of classification.

Non-current assets classified as held for sale are measured at the lower of the carrying amount and fair value less costs to sell, with impairments recognized in the consolidated statement of comprehensive income (loss) in the period measured. Non-current assets held for sale are presented in current assets and liabilities within the balance sheet. Assets held for sale are not depleted, depreciated or amortized.

Income and expenses related to discontinued operations are classified as income (loss) from discontinued operations within the consolidated statements of comprehensive income (loss) and the consolidated statement of cash flows.

g) Crude oil inventory

Crude oil inventory consists of crude oil in transit at the balance sheet date and is valued at the lower of cost, using the weighted average cost method, and net realizable value. Costs include direct and indirect expenditures incurred in bringing the crude oil to its existing condition and location.

h) Purchased oil

Purchased oil includes costs to buy third party oil. These costs are initially recorded in inventory until the crude oil title is transferred.

i) Goodwill

Goodwill is recorded on a business acquisition when the purchase price is in excess of the fair values assigned to assets acquired and liabilities assumed. Goodwill is not amortized and an impairment test is performed annually or as events occur that could indicate impairment. To test for impairment, goodwill is allocated to each of the Company's CGUs, groups of CGUs, or an operating segment expected to benefit from the acquisition. Goodwill is tested by combining the carrying amounts of property, plant and equipment and exploration and evaluation assets and goodwill and comparing this to the recoverable amount. Fair value less costs of disposal, is derived by estimating the discounted after-tax future net cash flows as described in the property, plant and equipment impairment test, plus the fair market value of undeveloped land, seismic and inventory. Value in use is assessed using the present value of the expected future cash flows. Any excess of the carrying amount over the recoverable amount is recorded as impairment. Impairment charges, which are not tax affected, are recognized in comprehensive income (loss) and are not reversed. Goodwill is reported at cost less any impairment.

j) Revenue recognition

Revenue from the sale of oil and natural gas is recorded when the significant risks and rewards of ownership of the product are transferred to the buyer which is usually when legal title passes to the external party.

k) Repurchase of shares

Pursuant of the Normal Course Issuer Bid ("NCIB"), repurchased common shares reduce share capital for the average book value with any excess or deficiency charged to retained earnings (deficit).

l) Share-based compensation

The Company has an incentive stock option plan and a restricted unit plan for certain employees, officers and directors as described in note 15. The Company records share-based compensation expense using the fair value method. The fair value of an option is calculated at the grant date using the Black-Scholes pricing model, and expensed over the vesting period of the option. The fair value of an RSU is calculated using the market price of Parex shares on the date of issuance, and expensed over the vesting period of the RSU. The Company determines an appropriate forfeiture rate by examining the history of its forfeitures. The Company records the cumulative share-based compensation as contributed surplus. When options or RSUs are exercised, contributed surplus is reduced and share capital is increased by the amount of accumulated share-based compensation for the exercised security. Any consideration received on the exercise of stock options or RSUs is credited to share capital.

Obligations for payments of cash under the foreign subsidiaries' SARs plan are accrued as compensation expense over the vesting period based on the fair value of SARs, subject to appreciation limits specified in the plan. The fair value of SARs is measured using the Black-Scholes pricing model. In accordance with the fair value method, increases or decreases in the fair value of the SARs result in a corresponding change in the recorded liability. The accrued compensation for a right that is forfeited is adjusted by decreasing compensation cost in the period of forfeiture.

m) Provisions

A provision is recognized if, as a result of a past event, the Company has a current legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

n) Decommissioning and environmental liabilities

The Company's activities give rise to dismantling, decommissioning, environmental, abandonment and site disturbance remediation activities. Provisions are made for the estimated cost of the future site restoration and capitalized in the relevant asset category.

Decommissioning and environmental liabilities are measured at the present value of management's best estimate of the cost and future timing of the expenditure required to settle the present obligation at the balance sheet date using a risk-free discount rate. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as a finance expense whereas increases (decreases) due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning and environmental liabilities are charged against the provision to the extent the provision was established.

o) Operating Segments

Management has determined the operating segments based on information regularly reviewed for the purposes of decision making, allocating resources and assessing operational performance by the Company's chief operating decision makers. The operating segments are Canada, Colombia and Trinidad & Tobago. The Company evaluates the financial performance of its operating segments primarily based on operating cash flow.

p) Finance income and expense

Finance expense comprises interest expense on borrowings, accretion on other provisions and convertible debentures, amortization of debt issuance costs, revaluation of derivative financial liabilities and impairment losses recognized on financial assets. Finance income comprises interest earned on cash and other income.

q) Cash

Cash is comprised of cash held in chartered banks in Canada and recognized financial institutions abroad with BBB+ credit ratings or higher.

r) Income taxes

Income tax expense comprises current and deferred tax. Income tax expense is recognized in comprehensive income (loss).

Current tax is the expected tax payable on taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

In general, deferred tax is recognized in respect of temporary differences arising between the tax basis of assets and liabilities and their carrying amounts in the consolidated financial statements. Deferred tax is determined on a non-discounted basis using tax rates and laws enacted or substantively enacted by the balance sheet date and expected to apply when the deferred tax asset or liability is settled. Deferred tax assets are recognized to the extent that it is probable that the assets can be recovered. Deferred tax is provided on temporary differences arising on investments in subsidiaries except, in the case of subsidiaries, where the timing of the reversal of the temporary difference is controlled by the Company and it is probable that the temporary difference will not be reversed in the foreseeable future. Deferred tax assets and liabilities are presented as non-current.

s) Per share information

Basic net income per share is calculated by dividing the income or loss attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. Diluted net income per share is determined by adjusting the income or loss attributable to common shareholders and the weighted average number of common shares outstanding for the effects of dilutive instruments such as options granted to employees and convertible debentures, except when the effect would be anti-dilutive.

t) Accounting policies adopted

The Company has reviewed new and revised accounting pronouncements that have been issued effective January 1, 2014 and determined the following impacts on the Company:

IAS 36 "Impairment of Assets" has been amended to reduce the circumstances in which the recoverable amount of cash generating units "CGUs" is required to be disclosed and clarify the disclosures required when an impairment loss has been recognized or reversed in the period. The amendment is effective retrospectively for annual periods beginning on or after January 1, 2014. As allowed by the standard, the Company early adopted the amendment in the year ended December 31, 2013. The retrospective adoption of these amendments impact the Company's disclosures in the notes to the financial statements in periods when an impairment loss is recognized.

IFRIC 21 "Levies" was developed by the IFRS Interpretations Committee ("IFRIC") and is applicable to all levies imposed by governments under legislation, other than outflows that are within the scope of other standards (e.g., IAS 12 "Income Taxes") and fines or other penalties for breaches of legislation. The interpretation clarifies that an entity recognizes a liability for a levy when the activity that triggers payment, as identified by the relevant legislation, occurs. It also clarifies that a levy liability is accrued progressively only if the activity that triggers payment occurs over a period of time, in accordance with the relevant legislation. Lastly, the interpretation clarifies that a liability should not be recognized before the specified minimum threshold to trigger that levy is reached. The adoption of this interpretation did not have an impact to the Company's financial statements.

IAS 32, "Financial Instruments: Presentation" ("IAS 32") has been amended to clarify that the right to offset financial assets and liabilities must be available on the current date and cannot be contingent on a future event. The adoption of this interpretation did not have an impact to the Company's financial statements.

u) New standards and interpretations not yet adopted

The standards and interpretations that are issued but not yet effective up to the date of issuance of the Company's financial statements, and that may have an impact on the disclosures and financial position of the Company, are disclosed below. The Company intends to adopt these standards and interpretations, if applicable, when they become effective.

- (i) On May 28, 2014, the IASB issued IFRS 15, "Revenue from Contracts with Customers" ("IFRS 15") replacing International Accounting Standard 11, "Construction Contracts" ("IAS 11"), IAS 18, "Revenue" ("IAS 18"), and several revenue-related interpretations. IFRS 15 establishes a single revenue recognition framework that applies to contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. Disclosure requirements have also been expanded. The new

standard is effective for annual periods beginning on or after January 1, 2017, with earlier adoption permitted. The standard may be applied retrospectively or using a modified retrospective approach. The Company is currently evaluating the impact of adopting IFRS 15 on the consolidated financial statements.

- (ii) On July 24, 2014, the IASB issued the final version of IFRS 9, “Financial Instruments” (“IFRS 9”) to replace IAS 39, “Financial Instruments: Recognition and Measurement” (“IAS 39”). IFRS 9 introduces a single approach to determine whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. For financial liabilities, IFRS 9 retains most of the IAS 39 requirements; however, where the fair value option is applied to financial liabilities, the change in fair value resulting from an entity’s own credit risk is recorded in OCI rather than net earnings, unless this creates an accounting mismatch. In addition, a new expected credit loss model for calculating impairment on financial assets replaces the incurred loss impairment model used in IAS 39. The new model will result in more timely recognition of expected credit losses. IFRS 9 also includes a simplified hedge accounting model, aligning hedge accounting more closely with risk management. Parex does not currently apply hedge accounting. IFRS 9 is effective for years beginning on or after January 1, 2018. Early adoption is permitted if IFRS 9 is adopted in its entirety at the beginning of a fiscal period. The Company is currently evaluating the impact of adopting IFRS 9 on the consolidated financial statements.

Critical Accounting Estimates

The preparation of consolidated financial statements in accordance with IFRS requires management to make judgments, assumptions and estimates that affect the financial results of the Company. The following discussion outlines the accounting policies and practices involving the use of estimates that the Company believes are critical in determining Parex’ financial results.

Oil and natural gas reserves

The Company retains qualified independent reserves evaluators to evaluate the Company’s proved and probable oil and natural gas reserves. As at December 31, 2014, Parex’ reserves were evaluated by GLJ Petroleum Consultants Ltd., who are a firm of qualified independent reserves evaluators. The evaluation was conducted in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*. The Operations and Reserves Committee of the Company’s Board of Directors is comprised of independent directors whose mandate is to steward the reserves evaluation process.

The estimation of reserves involves the exercise of judgment. Forecasts are based on engineering data, expected rates of production and the timing of future capital expenditures, all of which are subject to major uncertainties and interpretations. The Company expects that over time its reserve estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels. Reserve estimates can have a significant impact on net income (loss), as they are a key component in the calculation of DD&A and for determining potential asset impairment. A downward revision in reserves estimates or an increase in estimated future development costs could result in the recognition of a higher DD&A charge to net income (loss).

Oil and natural gas assets (development and producing costs) are aggregated into CGUs based on their ability to generate largely independent cash flows. If the carrying value of the CGU exceeds the recoverable amount, the CGU is written down with an impairment recognized in net income (loss). The recoverable amount of an asset or CGU is the greater of its fair value less costs to sell and its value in use. Fair value less costs to sell may be determined using discounted future net cash flows of proved plus probable reserves using forecast prices and costs. A downward revision in reserves estimates could result in the recognition of impairments charged to net income (loss).

Reversals of impairments are recognized when there has been a subsequent increase in the recoverable amount. In this event, the carrying amount of the asset or CGU is increased to its revised recoverable amount with an impairment reversal recognized in net income (loss).

Decommissioning and environmental liabilities

The Company is required to recognize a liability for future dismantling, decommissioning, environmental, abandoning and site disturbance remediation costs associated with the Company’s oil and natural gas properties in accordance with existing laws, contracts or other policies. The fair value of the estimated decommissioning and environmental liability is recorded as a long-term liability, with a corresponding increase in the carrying amount of the related long-

lived asset, which is depleted on a unit-of-production basis over the life of the reserves. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to net income (loss), and for revisions to the estimated future cash flows. Actual costs incurred upon settlement of the obligations are charged against the liability.

Decommissioning and environmental liabilities are determined by using management's best estimate of costs, taking into account the anticipated method and extent of restoration consistent with legal requirements, technological advances, industry practices and the possible use of the site. Since these estimates are specific to the sites involved, there are many individual assumptions underlying the Company's total decommissioning and environmental liability. These individual assumptions can be subject to change based on experience. Restoration technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. The Company estimates future decommissioning and environmental costs based on current estimates adjusted for inflation. This estimate for inflation is also subject to management uncertainty.

Current and Deferred tax

The Company follows the liability method of accounting for income taxes. Under this method, future tax assets and liabilities are determined based on differences between the financial reporting and tax basis of assets and liabilities and are measured using substantially enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect of a change in income tax rates on deferred tax liabilities and assets is recognized in net income (loss) in the period that the change occurs. Deferred tax assets are only recognized to the extent that it is probable that sufficient future taxable income will be available in the applicable jurisdiction to allow the deferred tax assets to be realized.

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations from multiple jurisdictions. Rates are also affected by legislative changes. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded in the financial statements. Estimates of current income tax for interim periods are also subject to additional uncertainty. A variety of factors cannot be known until year-end and, therefore, estimates are used for interim period current tax provisions.

Share-based compensation

The Company records stock-based compensation expense using the fair value method. The fair value of an option is calculated at the grant date, and expensed equally over the vesting term of the option. The Company records the cumulative stock-based compensation as contributed surplus. When options are exercised, contributed surplus is reduced and share capital is increased by the amount of accumulated stock-based compensation for the exercised option. Any consideration received on the exercise of stock options is credited to share capital.

The determination of stock-based compensation expense is based on assumptions regarding stock volatility, risk-free interest rates and the expected life of the options. These assumptions, by their nature, are subject to measurement uncertainty.

Obligations for payments of cash under the subsidiaries' SARs plan are accrued as compensation expense over the vesting period based on the fair value of SARs, subject to appreciation limits specified in the plan. The fair value of SARs is measured using the Black-Scholes pricing model. In accordance with the fair value method, increases or decreases in the fair value of the SARs result in a corresponding change in the recorded liability. The accrued compensation for a right that is forfeited is adjusted by decreasing compensation cost in the period of forfeiture.

The determination of SARs expense is based on assumptions regarding stock volatility, risk-free interest rates and the expected life of the SAR. These assumptions, by their nature, are subject to measurement uncertainty.

The fair value of an RSU is calculated using the market price of Parex shares on the date of issuance, and expensed over the vesting period of the RSU

Goodwill

Goodwill represents the excess of purchase price over fair value of net assets acquired, and is assessed for impairment annually at December 31 of each year. To test for impairment, goodwill is allocated to each of the Company's CGUs, or groups of CGUs, that are expected to benefit from the acquisition and is tested as described above in the Company's impairment policy. The recoverable amount of an asset or a CGU is the greater of its value in use and its FVLCD.

Value in use is determined by estimating the present value of the future net cash flows expected to be derived from the continued use of the asset or CGU. FVLCD is based on available market information, where applicable. In the absence of such information, FVLCD is determined using discounted future net cash flows of proved plus probable reserves using forecast prices and costs. A downward revision in reserves estimates could result in the recognition of a goodwill impairment charge to net earnings.

These calculations require the use of estimates and assumptions and are subject to changes as new information becomes available including information on future commodity prices, expected production volumes, quantity of reserves and discount rates as well as future development and operating costs. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGUs.

Derivative liabilities

Prior to its conversion and redemption, the convertible feature of the convertible debentures was required to be fair-valued at each balance sheet date. The fair value of this derivative liability was calculated using the Black-Scholes pricing model which is based on significant assumptions such as volatility of the market price of Parex' shares, the risk free interest rate (based on government of Canada Bonds), and the share price of Parex' stock at the measurement date.

Risk management contracts are initially recognized at fair value on the date a derivative contract is entered into and are remeasured at their fair value at each subsequent reporting date. The fair value of the risk management contract on initial recognition is normally the transaction price. Subsequent to initial recognition, the fair value are based on quoted market price where available from active markets, otherwise fair values are estimated based on market prices at the reporting date for similar assets or liabilities with similar terms and conditions.

Legal, environmental remediation and other contingent matters

In respect of these matters, the Company is required to determine both whether a loss is probable based on judgment and interpretation of laws and regulations and if such a loss can reasonably be estimated. When any such loss is determined, it is charged to net income (loss). Management continually monitors known and potential contingent matters and makes appropriate provisions by charges to net income (loss) when warranted by circumstances.

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Robert J. Engbloom

Wayne K. Foo

Ron D. Miller

W. A. (Alf) Peneycad

Paul D. Wright

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David R. Taylor
*Executive VP Exploration & Business
Development*

Stu R. Davie
VP Human Resources & Administration

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ABBREVIATIONS

Oil and Natural Gas Liquids

bbbls
mbbls
mmbbls
NGLs
bbbls/d or bopd
mbbls/d
BOE or boe
mboe
mmboe
bfpd
boe/d

barrels
one thousand barrels
one million barrels
natural gas liquids
barrels of oil per day
one thousand barrels per day
barrel of oil equivalent, using the conversion factor of 6 Mcf: 1 bbl
one thousand barrels of oil equivalent
one million barrels of oil equivalent
barrels of fluid per day
barrels of oil equivalent per day

Other

WTI
Brent

West Texas Intermediate
Brent Ice

"BOEs" may be misleading, particularly if used in isolation. A BOE conversion ratio of nine thousand cubic feet of natural gas to one barrel of oil equivalent (6 mcf: 1 bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.