PACIFIC RUBIALES ENERGY CORP.

MANAGEMENT DICUSSION AND ANALYSIS

March 13, 2014

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For the year ending December 31, 2013

CONTENTS

This Management Discussion and Analysis ("**MD&A**") contains forward-looking information based on the current expectations, estimates, projections and assumptions of Pacific Rubiales Energy Corp. This information is subject to a number of risks and uncertainties, many of which are beyond the Company's control. Users of this information are cautioned that actual results may differ materially. For information on material risk factors and assumptions underlying our forward-looking information, see page 46.

This MD&A is management's assessment and analysis of the results and financial condition of the Company, and should be read in conjunction with the accompanying Audited Annual Consolidated Financial Statements and related notes for the years ending December 31, 2013 and December 31, 2012. The preparation of financial information is reported in United States dollars and is in accordance with International Financial Reporting Standards ("**IFRS**") as issued by the International Accounting Standards Board ("**IASB**") unless otherwise noted. All comparative percentages are between the years and quarters ending December 31, 2013 and December 31, 2012 unless otherwise stated.

In order to provide shareholders with full disclosure relating to potential future capital expenditures, the Company has provided cost estimates for projects that in some cases are still in the early stages of development. These costs are preliminary estimates only. The actual amounts are expected to differ and these differences may be material. For further discussion of the significant capital expenditures, see "Capital Expenditures" on page 19.

Additional Company information filed with Canadian securities regulatory authorities, including the Company's quarterly and annual reports and the Annual Information Form, are available on SEDAR at www.sedar.com, SIMEV at www.superfinanciera.gov.co/web_valores/Simev, BOVESPA at www.bmfbovespa.com.br and on the Company's website at www.pacificrubiales.com. Information contained in or otherwise accessible through our website does not form a part of this MD&A and is not incorporated by reference into this MD&A.

This MD&A was prepared originally in the English language and subsequently translated into Spanish and Portuguese. In the case of differences or discrepancies between any of its translated versions, the English document shall prevail and be treated as the governing version.

1. Company Overview and Strategy

Pacific Rubiales is a leading oil and gas exploration and production company publicly listed on the Toronto and Colombian stock exchanges. We are the largest independent oil and gas producer in Colombia, additionally focused on identifying growth opportunities in Colombia, Peru, Brazil, Guatemala, and other countries in the region. The Company has a strong and growing reserve base, a proven track record of cash generation, and a robust portfolio of exploration assets.

Business Strategy

Our near-and medium-term business strategy is focused on:

- Replacement of the Rubiales field by 2016;
- Operational efficiency and cost reduction;
- Accretive acquisitions: operational synergies; turn around of underperforming fields and growth potential.
- Reserve and production diversification within and beyond Colombia;
- Delivering attractive returns to shareholders; and
- Long-term sustainable growth through innovation: LNG; enhanced oil recovery and exploration.

2013 Operational Summary

2013 was a transformational year for the Company in terms of organic growth in production, significant oil discoveries in Brazil, Colombia and Peru and the successful acquisition of Petrominerales, which provided us with a portfolio of high-quality assets including additional light oil for use as a lower-cost diluent source and interests in strategic infrastructure. Our oil and gas production exceeded the target set for the year and reached a record level at the end of 2013. As a significant long-term business objective, we were able to further diversify our reserve base beyond the Rubiales field, which now represents only 11% of total 2P reserves. As part of our near-term objective of replacing the production from Rubiales, large heavy oil fields such as CPE-6 and the newly acquired Rio Ariari are now under a significant development program to rapidly bring production on-line.

During 2013, we once again delivered solid financial results as all cash flow indicators including adjusted EBITDA and funds flow from operations reached record levels. We were able to maintain a strong operating netback consistent with last year despite a drop in international oil and gas benchmark prices. We made significant progress in reducing our operating costs through a series of projects announced earlier in the year such as a reduction in purchased diluents, the Bicentenario pipeline, and the PEL power transmission line.

Financial Management

Our capital management strategy is to invest in projects that focus on short-term production ramp-up and reserve growth in the medium term while delivering an attractive return to our shareholders. We made a series of large strategic acquisitions in 2012 and 2013 to in order to meet those objectives and still maintain a healthy financial leverage. At the end of 2013, our debt to EBITDA ratio was in line with our target of between 1 and 1.5 times, while keeping the flexibility for further investment in accretive capital projects. We have signed an agreement to sell the OCENSA pipeline interest that was acquired through the Petrominerales acquisition for $385 million, and are also in the process of evaluating investment partners for some of our other infrastructure assets. We expect to unlock additional value for our shareholders through these transactions and use the proceeds to reduce our long-term debt. During 2013, we paid a total of $196 million in dividends to our shareholders and started a share repurchase program in November 2013, which will continue in 2014.

Focus Areas for 2014

2014 will require that the Company continue to execute our strategy, which entails the following:

- A target for raising production primarily in the CPE-6 and Rio Ariari blocks, expected to further reduce the relative importance of the Rubiales field;
- Continuing to lower operating costs through the commissioning of the Bicentenario pipeline in late 2013 and the PEL power transmission in early 2014;
- Integrating the recently-acquired assets and capturing the cost and transportation synergies;
- Capitalizing on the discoveries made in Peru and Brazil and continuing to expand our portfolio in Latin America;
- Continuing to optimize our exploratory and producing field portfolio to improve the return to shareholders;
- Enhancing shareholder value through monetization of our infrastructure assets, balancing growth with returns through dividends and share repurchases; and
- Focusing on cash generation and growth in production and reserves.

2. 2013 Financial and Operating Highlights

Financial Summary

(in thousands of US$ except per share amounts or as noted)	Year Ended December 31 2013	Year Ended December 31 2012	Three Months Ended December 31 2013	Three Months Ended December 31 2012
Oil and gas sales	**$ 4,626,859**	$ 3,884,762	**$ 1,202,551**	$ 1,046,689
Adjusted EBITDA [1]	**2,566,957**	2,019,956	**655,327**	429,589
Adjusted EBITDA margin (Adjusted EBITDA/Revenues)	**55%**	52%	**54%**	41%
Per share - basic ($) [2]	**7.95**	6.85	**2.02**	1.45
Funds flow from operations [1]	**1,913,112**	1,387,544	**476,851**	231,532
Funds flow from operations margin (Funds flow from operations/Revenues)	**41%**	36%	**40%**	22%
Per share - basic ($) [2]	**5.92**	4.71	**1.47**	0.78
Net earnings from operations [1]	**1,148,148**	1,033,550	**312,426**	121,376
Per share - basic ($) [2]	3.55	3.51	0.96	0.41
Net earnings [3]	**430,405**	527,729	**142,958**	(23,777)
Per share - basic ($) [2]	**1.33**	1.79	**0.44**	(0.08)
Adjusted net earnings [1]	**490,218**	650,852	**152,123**	58,698
Per share - basic ($) [2]	**1.52**	2.21	**0.47**	0.20
Capital expenditures	**2,065,525**	1,548,196	**625,398**	601,356
Capital expenditures for new acquisitions and Farm-in	**1,133,522**	1,128,165	**1,020,475**	658,647
(COP$ / US$) exchange rate [4]	**1,926.83**	1,768.23	**1,926.83**	1,768.23

1. *See "Additional Financial Measures" on page 42.*
2. *The basic weighted average number of common shares outstanding for the year ending December 31, 2013 and 2012 was 322,989,949 and 294,576,424, respectively. The same for the fourth quarter of 2013 and 2012 were 324,173,884 and 296,284,151, respectively.*
3. *Net earnings attributable to equity holders of the parent.*
4. *COP/USD exchange rate fluctuations can have a significant impact on the Company's accounting net earnings, due in the form of unrealized foreign currency translation on the Company´s financial assets and liabilities and deferred tax balances that are denominated in COP.*

Operating Summary

	Year Ended December 31 2013	Year Ended December 31 2012	Three Months Ended December 31 2013	Three Months Ended December 31 2012
Average net production (boe/d)	**129,386**	97,657	**134,313**	108,149
Average sales volumes (boe/d)	**134,621**	108,980	**143,864**	120,141
Crude oil netback ($/bbl)	**63.60**	63.14	**62.31**	47.61
Gas netback ($/boe)	**29.44**	35.01	**25.36**	35.08
Combined netback ($/boe)	**60.77**	60.20	**59.43**	46.44
2P Reserves (MMboe)	**619.20**	513.70	**619.20**	513.70

2013 Highlights

Strong Cash Flow Generation and Financial Results

- 19% increase in revenue year-over-year, from $3.9 billion to $4.6 billion despite reduction in international oil prices and the accommodation for approximately 0.5 MMbbl of production used to fill the Bicentenario pipeline and the 1.3 MMbbl delivered to Ecopetrol as part of the high-prices clause arbitration decision at Quifa SW (“PAP”).
- 27% increase in adjusted EBITDA from $2.0 billion to $2.6 billion, representing a 55% margin on revenue.
- Funds flow from operations increased from $1.4 billion to $1.9 billion, a 41% margin on revenue.
- Earnings from operations increased from $1.0 billion to $1.1 billion; net earnings decreased from $0.5 billion to $0.4 billion year-over-year.

Significant Increase in Daily Net Production and Combined Netbacks

- 32% increase year-over-year in daily net production to 129,386 boe/d, surpassing the high end of the Company’s guidance for 2013 (113,000 -127,000 boe/d).
- Average net production for the fourth quarter of 2013 reached 134,313 boe/d, a 24% increase from the fourth quarter of 2012.
- Operating netback increased to $60.77/boe in 2013 from $60.20/boe in 2012.
- Reduction of oil operating costs by $7.46/bbl compared to the fourth quarter of 2012, substantially in line with the target of $8/bbl.

21% Growth in Proved plus Probable reserves (“2P”)

- Total 2P net after royalties reserves grew to 619.2 MMboe at December 31, 2013, up 21% from 513.7 MMboe at December 31, 2012, achieving a 2P reserves replacement ratio of 324%. Total net proved reserves ("**1P**") grew by 17% in the same period to 394.1 MMboe.
- Significant reserve additions resulted from acquisitions (totaling 89 MMboe), including first reserves bookings an production in onshore Colombia from the Petrominerales acquisitions, and in 2012 the acquisitions of PetroMagdalena and C&C, and offshore Peru in Block Z-1. At year-end 2013, the Company continued its successful reserves base diversification, the Rubiales field now representing less than 11% of total 2P reserves.

Exploration Success in Colombia and Peru and Acquisitions

- First oil production from CPE-6 at 185 bbl/d at the end of 2013.
- New discoveries in the CPE-6, Quifa, Cravoviejo, Cachicamo, Casanare Este and Casimena blocks in Colombia.
- Light oil discovery in Block 131 and Block 126 in Peru, acquired as part of the Petrominerales acquisition.
- Block Z-1 in offshore Peru reported in March 2014 a 165% increase in average gross production.
- Three new offshore exploration blocks awarded in the 2013 Brazil Round 11.
- $2.1 billion of executed capital investment in 2013 compared to $1.5 billion in 2012. Also paid $1.0 billion in cash acquisiton cost of Petrominerales and the assumption of approximately $0.7 billion in long-term debt.

Projects Update

- STAR secondary recovery technology demonstrated at least a doubling of the primary recovery factor at the Quifa SW pilot project.
- Bicentenario pipeline between Araguaney Station and Banadia Station commenced operation in the fourth quarter.
- Start-up of the PEL electrical power transmission line in January 2014, delayed from December 2013 due to regulatory approvals.
- Execution of a Heads of Agreement with GAZPROM in November 2013 for a five-year agreement to sell approximately 0.5 million tonnes per year of liquefied natural gas commencing in the second quarter of 2015.
- Investment of $150 million by International Finance Corporation, a member of the World Bank Group, for a 27.2% interest in the equity of Pacific Infrastructure Ventures Inc. ("**Pacific Infrastructure**").

Financing

- Successful issuance of unsecured senior notes totaling $2.6 billion during 2013.
- Paid a total of $196 million in quarterly dividends in 2013.
- Started a share repurchase program in November 2013. As of March 12, 2014, we have repurchased approximately 10.7 million common shares for a total of $163 million.

3. Financial Summary

A summary of the financial results for the three and twelve months ending December 31, 2013 and 2012 are as follows:

Results of 2013 Compared to 2012

Revenue for 2013 was $4,627 million, 19% higher than the $3,885 million of 2012. Revenue for the fourth quarter of 2013 ($1,203 million) was also higher than the fourth quarter revenue in 2012 ($1,047 million). During 2013, the total sales volume of crude and natural gas amounted to 49.1 MMboe compared to 39.8 MMboe during 2012, mainly as a result of the 32% increase in net production to 129,386 boe/d from 97,657 boe/d year-on-year.

Adjusted net earnings and net earnings for 2013 were $490 million and $430 million respectively, compared to $651 million and $528 million reported in 2012, impacted by higher depreciation, depletion and amortization, finance costs, income tax and costs related to acquisitions. The Company's net earnings were also influenced by fluctuations in COP/US$ exchange rates and non-cash items such as unrealized gain or loss on risk management contracts. Net earnings from operations[1] for 2013 were $1,148 million, compared to $1,034 million in 2012. A reconciliation of the net earnings to the net earnings from operations follows.

	Year Ended December 31		Three Months Ended December 31	
(in thousands of US$)	**2013**	**2012**	**2013**	**2012**
Net earnings	**$ 430,405**	$ 527,729	**$ 142,958**	$ (23,777)
Finance costs	**162,402**	92,860	**43,298**	24,881
Share of loss of equity-accounted investees	**29,147**	102,933	**15,227**	60,851
Foreign exchange (gain) loss	**(6,325)**	(577)	**4,655**	(13,421)
Loss (gain) on risk management	**2,530**	(10,130)	**(9,801)**	13,663
Other expenses (income)	**34,461**	30,897	**(916)**	21,382
Income tax expense	**504,976**	289,838	**119,229**	37,797
Loss attributable to non-controlling interest	**(9,448)**	-	**(2,224)**	-
Net earnings from operations [1]	**$ 1,148,148**	$ 1,033,550	**$ 312,426**	$ 121,376

1. *See "Additional Financial Measures" on page 42.*

Strong Cash Flow from Operations and Adjusted EBITDA

Adjusted EBITDA totaled $2,567 million, an increase of 27% compared to $2,020 million in 2012, and represented a 55% margin on total revenues for the period compared to a 52% margin in 2012. Funds flow from operations increased to $1,913 million in 2013, significantly higher than $1,388 million in 2012. Funds flow from operations margin increased to 41% in 2013 from 36% in 2012. Cash flow from operations was $1,637 million for 2013 compared to $1,803 million for 2012, primarily due to the movement in net working capital. The combined oil and gas realized price for 2013 was $93.95/boe, lower by $2.63/boe compared to 2012. Lower prices can be attributed to a reduction in the premium on WTI due to a decline in the market ICE Brent – WTI NYMEX differential.

Additional details on financial results for 2013 are provided in Section 9 - Discussion of 2013 Financial Results on page 26.

4. Operating Results

During 2013 the Company achieved higher combined operating netbacks despite the 3% reduction on the realized price due to market conditions. The Company was able to accomplish a significant reduction in operating costs, mitigating the decrease in realized prices and achieving a combined netback of $60.77/boe versus $60.20/boe for 2012. Crude oil operating netback remained strong at $63.60/bbl compared to $63.14/bbl for 2012, mainly attributable to an overall reduction of oil operating costs as part of the previously announced cost reduction initiatives by the Company.

Operating Netback –Oil and Gas Produced and Sold

Below is a summary of the combined operating netback for the total crude oil and natural gas sold during 2013 and 2012, including diluents but excluding trading volumes:

	Three months ended December 31					
	2013			2012		
	Crude Oil	Natural Gas	Combined	Crude Oil	Natural Gas	Combined
Average daily volume sold (boe/day)[1]	**129,547**	**10,918**	**140,465**	**107,392**	**11,031**	**118,423**
Operating netback ($/boe)						
Crude oil and natural gas sales price	95.54	32.69	90.66	99.83	43.80	94.61
Production cost of barrels sold [2]	14.80	4.24	13.98	14.78	6.61	14.02
Transportation (trucking and pipeline) [3]	13.29	-	12.26	14.57	0.01	13.22
Diluent cost [4]	2.32	-	2.14	8.52	-	7.72
Total operating cost	**30.41**	**4.24**	**28.38**	**37.87**	**6.62**	**34.96**
Overlift/Underlift [5]	(1.71)	0.07	(1.57)	9.21	(0.89)	8.27
Other costs [6]	4.53	3.02	4.42	5.14	2.99	4.94
Total operating cost including overlift/underlift and other costs	**33.23**	**7.33**	**31.23**	**52.22**	**8.72**	**48.17**
Operating netback crude oil and gas ($/boe)	**62.31**	**25.36**	**59.43**	**47.61**	**35.08**	**46.44**

	Year ended December 31					
	2013			2012		
	Crude Oil	Natural Gas	Combined	Crude Oil	Natural Gas	Combined
Average daily volume sold (boe/day)[1]	**120,002**	**10,787**	**130,789**	**93,141**	**10,902**	**104,043**
Operating netback ($/boe)						
Crude oil and natural gas sales price	99.05	37.27	93.95	102.94	42.19	96.58
Production cost of barrels sold [2]	15.24	5.11	14.41	11.71	4.60	10.96
Transportation (trucking and pipeline) [3]	14.54	0.10	13.35	13.95	0.20	12.51
Diluent cost [4]	5.46	-	5.01	11.08	-	9.92
Total operating cost	**35.24**	**5.21**	**32.77**	**36.74**	**4.80**	**33.39**
Overlift/Underlift [5]	(1.56)	-	(1.43)	1.94	(0.27)	1.71
Other costs [6]	1.77	2.62	1.84	1.12	2.65	1.28
Total operating cost including overlift/underlift and other costs	**35.45**	**7.83**	**33.18**	**39.80**	**7.18**	**36.38**
Operating netback crude oil and gas ($/boe)	**63.60**	**29.44**	**60.77**	**63.14**	**35.01**	**60.20**

1. *Combined operating netback data based on weighted average of daily volume sold which includes diluents necessary for the blending of the Rubiales crude oil, and excludes oil for trading volumes.*
2. *Cost of production mainly includes lifting cost and other direct production costs such as fuel consumption, outsourced energy, fluid transport (oil and water), and personnel expenses and workovers, among others. Increases in oil production cost are driven by higher fluid (mainly water) production, which affects fuel consumption, outsourced energy and fluid transport costs, as compared to the prior periods of 2012.*
3. *Includes the transport costs of crude oil and gas through pipelines and tank trucks incurred by the Company when taking the products to the delivery points for customers.*
4. *See additional discussion on diluent costs below.*
5. *Corresponds to the net effect of the overlift position of $20.3 million during the fourth quarter of 2013 ($68.3 million for the year 2013).*
6. *Other costs mainly correspond to inventory fluctuation, storage cost and the net effect of the currency hedges of operating expenses incurred in Colombian pesos during the period, as well as royalties paid in cash on gas and oil production and external road maintenance at the fields.*

For the fourth quarter of 2013, the combined crude oil and gas operating netback was $59.43/boe, higher by $12.99/boe as compared to the same period of 2012 ($46.44/boe). Crude oil operating netback was $62.31/bbl, a 31% increase as compared to the same period of 2012 ($47.61/bbl). Included in the crude oil netback for the fourth quarter of 2012 was $8.87/bbl of accrual related to the settlement of the high-price clause for the Quifa SW field to Ecopetrol. Excluding this one-time accrual, crude oil netback increased from $55.31/bbl to $62.31/bbl for the fourth quarter of 2013.

The combined realized price for the fourth quarter of 2013 was $90.66/boe, 4% lower than in the fourth quarter of 2012 ($94.61/boe) as a result of a general drop in Latin American crude prices due to the reduction in ICE Brent – WTI NYMEX differentials. The decrease in realized prices was more than offset by a $7.46/bbl reduction in oil operating cost (production, transportation and diluent costs). This was a result of the Company's cost reduction initiative announced in early 2013. The progress of the cost-reduction initiative is explained further in the "Operating Costs and Cost Reduction Initiatives" section. Compared to the third quarter of 2013, the realized price decreased by $6.63/boe from $97.29/boe while total operating cost decreased from $34.26/boe to $28.38/boe, mainly attributed to reductions in production, transportation, and diluent costs.

For the year 2013, the Company increased its combined operating netback to $60.77/boe compared to $60.20/boe in 2012. Crude oil operating netback during 2013 also remained strong at $63.60/bbl compared to $63.14/bbl for 2012.

The combined realized price in 2013 was $93.95/boe, 3% lower than the price of $96.58/boe in 2012, as a result of the decrease in the ICE Brent – WTI NYMEX price differential. Total operating costs (excluding other and overlift/underlift) was $32.77/boe in 2013 versus $33.39/boe in 2012, a combination of a higher production and transportation cost offset by a decrease in diluent cost.

Operating Costs and Cost Reduction Initiatives

Total combined operating costs for the fourth quarter of 2013 excluding overlift/underlift and other (which largely reflect inventory adjustments and other accounting and financial items), was $28.38/boe, lower by $6.58/boe from the same quarter in 2012 ($34.96/boe). For the fourth quarter of 2013, the Company was able to achieve an overall reduction in its oil operating costs (production, transportation and diluent costs) by $7.46/bbl compared to the same period of 2012, substantially achieving the targeted pro-forma $8/bbl announced by the Company in early 2013. The reductions achieved to date and the cost-reduction initiatives that are still under way are summarized below:

- Production cost decreased slightly from $14.02/boe in the fourth quarter of 2012 to $13.98/boe in the fourth quarter of 2013. In the fourth quarter of 2013, the Company delivered 598 Mbbl of crude oil in relation to the PAP settlement for the Quifa field that would have otherwise been sold; the delivery began in the third quarter of 2013. As such, the approximate cost of 0.62/bbl related to these barrels was included in production cost. During the first half of 2014, production cost is expected to decrease upon completion of the PEL power transmission line (regulatory approval for the start-up energization of the line was delayed from end of December 2013 to January 20, 2014) and the agricultural irrigation project, which will reduce energy and water treatment costs at the Rubiales and Quifa fields.

- Transportation cost decreased from $13.22/boe in the fourth quarter of 2012 to $12.26/boe in the same quarter of 2013. The Company reduced the volume of crude oil transported by truck participation from 35% in the fourth quarter of 2012 to 31%, compared to the same period of 2013 and the Bicentenario pipeline became operational during the fourth quarter of 2013. The Company also obtained additional capacity on the OCENSA pipeline through the Petrominerales acquisition, which will increase volume transported by pipeline to Coveñas moving forward.

- Combined diluent cost decreased by $5.58/bbl to $2.14/bbl in the last quarter of 2013 from $7.72/bbl in the same period in 2012. During 2013, the Company structurally reduced the relative volume of purchased diluents by using a higher volume of its own light and medium crude oil for blending. Additionally, implementation of the Cusiana blending project allowed us to increase the volume of our light crude to be used in blending. The blending ratio using natural gasoline for the Rubiales blend is now 7.13% in the fourth quarter of 2013 versus 14.55% in the fourth quarter of 2012.

Operating Netback for Fourth Quarter of 2013 Compared to Fourth Quarter of 2012

The combined crude oil and gas operating netback during the fourth quarter of 2013 was $59.43/boe, higher by $12.99/boe as compared with the same period of 2012 ($46.44/boe). Crude oil operating netback during the fourth quarter of 2013 was $62.31/bbl, 31% higher as compared to the same period of 2012 ($47.61/bbl).

The combined oil and gas realized price in the fourth quarter of 2013 was $90.66/boe, lower in comparison to the $94.61/boe in the fourth quarter of 2012 primarily due to lower oil prices.

Combined diluent costs were significantly reduced to $2.14/bbl in the fourth quarter of 2013 compared to $7.72/bbl in the same period of 2012, which was the result of using a higher volume of the Company's own light and medium crude oil for blending instead of importing natural gasoline.

Operating Netback - Crude Oil Trading

In addition to selling the crude it produces, the Company also purchases crude oil from third parties for trading purposes.

Fourth Quarter 2013

The netback on crude trading activities during the fourth quarter of 2013 was lower than the same period of 2012, mainly due to an increase in the cost of purchases relative to sales price, as indicated below:

Crude oil trading	Three months ended December 31	
	2013	2012
Average daily volume sold (bbl/d)	**3,399**	**1,718**
Operating netback ($/bbl)		
Crude oil traded sales price	99.11	100.66
Cost of purchases of crude oil traded	98.35	96.99
Operating netback crude oil trading ($/bbl)	**0.76**	**3.67**

Full Year 2013

The netback on crude trading activities during 2013 was lower than 2012 mainly due to a decrease in realized prices, as indicated below:

Crude oil trading	Year ended December 31	
	2013	2012
Average daily volume sold (bbl/d)	**3,832**	**4,937**
Operating netback ($/bbl)		
Crude oil traded sales price	101.40	114.62
Cost of purchases of crude oil traded	99.86	111.24
Operating netback crude oil trading ($/bbl)	**1.54**	**3.38**

Oil and Gas Production

During 2013, average net production after royalties and internal consumption totaled 129,386 boe/d, surpassing the high end of the Company's guidance for 2013 (113,000 -127,000 boe/d) and representing an increase of 32% year-over-year. Average net production for the fourth quarter of 2013 reached 134,313 boe/d, resulting in a 24% increase from the average net production reported for the fourth quarter of 2012.

Average Daily Oil and Gas Production – Net Volumes Before and After Royalties

The following table sets out the average daily net production after royalties for the Company's producing regions:

	Average Production (in boe/d)			
	Net share after royalties			
	Year ended December 31		Three months ended December 31	
Colombia	**2013**	**2012**	**Q4 2013**	**Q4 2012**
Central [1]	117,205	85,247	122,079	95,593
North [2]	10,781	10,837	10,811	11,099
South [3]	45	-	179	-
Total Production - Colombia	128,031	96,084	133,069	106,692
Peru				
Offshore Basin	1,355	1,573	1,244	1,457
Total Production - Peru	1,355	1,573	1,244	1,457
Total Production Colombia and Peru	129,386	97,657	134,313	108,149

1. *Includes Upper and Middle Magdalena Valley, Cordillera and Eastern Llanos basins.*
2. *Includes Lower Magdalena Valley, Cesar Rancheria and Catatumbo basins.*
3. *Includes Caguan-Putumayo basin.*

Oil and Gas Production in Colombia

Average net production after royalties in Colombia rose to 128,031 boe/d (308,411 boe/d total field production) for 2013 from 96,084 boe/d (243,264 boe/d total field production) in 2012, representing an increase of 33% compared to 2012, mainly due to:

- Drilling of 169 development wells at the Rubiales field, 76 development wells at the Quifa SW field, 10 wells at the Cajúa field and 49 wells in other producing fields. Additionally, there was an increase in the capacity of the production facilities at Rubiales and Quifa. Net production at Rubiales and Quifa increased 15% while the La Creciente natural gas field decreased by 1% as compared to 2012.
- Licence modification for the water disposal in the Rubiales field received in August 2012 allowed for the injection of an additional 400,000 barrels of water per day.
- Net production after royalties contributed by the PetroMagdalena, C&C Energia and Petrominerales acquisitions totaled 6,380 boe/d (total field production of 11,602 boe/d), 11,426 bbl/d (total field production of 12,467 bbl/d) and 2,077 bbl/d (total field production of 2,332 bbl/d) respectively, representing 15% of the total net production after royalties.

During the fourth quarter of 2013, net production after royalties and field consumption averaged was 133,069 boe/d (total gross field 313,416 boe/d). This volume is higher by 25% as compared to the same period of 2012.

Oil and Gas Production in Peru

Production from Peru corresponds to the 49% participating share of production from Block Z-1. Net production after royalties for 2013 from Block Z-1 was 1,355 bbl/d (total gross field production of 2,766 bbl/d). Additionally, net production for the fourth quarter of 2013 attributed from Block Z-1 averaged 1,244 bbl/d (total gross field 2,539 bbl/d).

On February 11, 2014, BPZ, our partner in the producing offshore Block Z-1, announced that the average gross production had reached approximately 5,425 bbl/d (total net field production of approximately 2,765 bbl/d), representing a 114% increase (104% on a net production basis) as compared to the average production reported for the fourth quarter of 2013.

The following table highlights the average daily production from all of the Company's producing fields located in Colombia and Peru for the three and twelve months ending December 31, 2013 and 2012:

Full-Year 2013 Production by Field

	Average Year Production (in boe/d)					
	Total field production		Gross share before royalties [1]		Net share after royalties	
Producing Fields - Colombia	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**
Rubiales / Piriri	208,763	177,015	87,768	74,113	70,214	59,285
Quifa SW [2]	55,031	46,701	32,754	27,851	23,610	22,070
Cravoviejo	9,545	-	9,510	-	8,749	-
Cubiro	8,854	2,196	5,446	1,408	5,036	1,295
Cajua	3,838	926	2,303	556	2,165	522
Cachicamo	2,717	-	2,717	-	2,500	-
Arrendajo	1,759	901	1,186	478	1,108	440
Abanico	1,256	1,584	350	454	334	436
Sabanero [3]	1,103	1,244	714	613	672	576
Dindal / Rio Seco	1,061	1,130	568	672	469	553
Casanare este	707	-	707	-	707	-
Casimena	324	-	323	-	301	-
Corcel	360	-	352	-	334	-
CPI Neiva	305	-	177	-	163	-
Guatiquia	485	-	485	-	446	-
New production at exploration areas [4]	29	-	22	-	21	-
Other producing fields [5] [6]	1,177	463	404	78	376	70
Total Production Central - Colombia	**297,314**	**232,160**	**145,786**	**106,223**	**117,205**	**85,247**
La Creciente [7]	10,761	10,864	10,543	10,662	10,543	10,660
Other producing fields [5] [6]	271	240	241	182	238	177
Total Production North - Colombia	**11,032**	**11,104**	**10,784**	**10,844**	**10,781**	**10,837**
Other producing fields [5] [6]	65	-	51	-	45	-
Total Production South - Colombia	65	-	51	-	45	-
Total Production - Colombia	**308,411**	**243,264**	**156,621**	**117,067**	**128,031**	**96,084**
Producing Fields - Peru (See note below)						
Block Z-1 [8]	2,766	3,311	1,355	1,596	1,355	1,573
Total Production - Peru	**2,766**	**3,311**	**1,355**	**1,596**	**1,355**	**1,573**
Total Production Colombia and Peru	**311,177**	**246,575**	**157,976**	**118,663**	**129,386**	**97,657**

Notes: Refer to the Fourth Quarter 2013 Production by Field on page 11.

Fourth Quarter 2013 Production by Field

	Average Q4 Production (in boe/d)					
	Total field production		Gross share before royalties (1)		Net share after royalties	
Producing Fields - Colombia	**Q4 2013**	**Q4 2012**	**Q4 2013**	**Q4 2012**	**Q4 2013**	**Q4 2012**
Rubiales / Piriri	204,308	192,395	85,571	80,975	68,456	64,756
Quifa SW (2)	55,348	49,271	32,896	29,373	22,586	23,040
Cravoviejo	9,629	-	9,587	-	8,820	-
Cubiro	10,281	5,877	6,276	3,783	5,821	3,480
Cajua	4,304	2,875	2,582	1,725	2,427	1,622
Cachicamo	2,966	-	2,966	-	2,728	-
Arrendajo	2,012	1,583	1,358	1,069	1,283	983
Abanico	1,236	1,479	338	408	323	390
Sabanero (3)	1,088	1,247	1,060	615	997	578
Dindal / Rio Seco	886	1,379	334	803	279	655
Casanare este	2,804	-	2,804	-	2,804	-
Casimena	1,287	-	1,280	-	1,194	-
Corcel	1,429	-	1,396	-	1,324	-
CPI Neiva	1,212	-	703	-	647	-
Guatiquia	1,924	-	1,924	-	1,770	-
New production at exploration areas (4)	113	-	87	-	82	-
Other producing fields (5) (6)	1,286	895	576	97	538	89
Total Production Central - Colombia	**302,113**	**257,001**	**151,738**	**118,848**	**122,079**	**95,593**
La Creciente (7)	10,820	11,072	10,606	10,833	10,606	10,831
Other producing fields (5) (6)	226	296	205	275	205	268
Total Production North - Colombia	**11,046**	**11,368**	**10,811**	**11,108**	**10,811**	**11,099**
Other producing fields (5) (6)	257	-	201	-	179	-
Total Production South - Colombia	**257**	**-**	**201**	**-**	**179**	**-**
Total Production - Colombia	**313,416**	**268,369**	**162,750**	**129,956**	**133,069**	**106,692**
Producing Fields - Peru (See note below)						
Block Z-1 (8)	2,539	2,973	1,244	1,457	1,244	1,457
Total Production - Peru	**2,539**	**2,973**	**1,244**	**1,457**	**1,244**	**1,457**
Total Production Colombia and Peru	**315,955**	**271,342**	**163,994**	**131,413**	**134,313**	**108,149**

1. *Share before royalties is net of internal consumption at the field and before PAP at the Quifa SW field.*
2. *The Company's share before royalties in the Quifa SW field is 60% and decreases in accordance to a high-price clause that assigns additional production to Ecopetrol.*
3. *On December 26, 2013, the ANH approved the transaction by which the Company acquired 100% of the Sabanero Block.*
4. *Includes CPE-6 and Rio Arirari. These fields are expected to add significant production volumes in 2014.*
5. *'Other producing fields' corresponds to producing assets located in Cerrito, Moriche, Las Quinchas, Guama, Topoyaco, Guasimo, Buganviles, Carbonera, Carbonera La Silla, Prospecto S, CPI Orito, Corcel Northeast, Yamu and Llanos 19 Blocks (Yamu is not an operated block). Subject to Ecopetrol´s and ANH´s approval (as applicable), the Company is in the process of divesting its participation in the Moriche, Las Quinchas, Guasimo, Chipalo, and Cerrito Blocks.*
6. *During the second quarter of 2013, the ANH requested the Company to pay in cash royalties related to crude oil for the Lisa, Yaguazo, Apamate, Cotorra and Cerro Gordo fields.*
7. *Royalties on production from La Creciente field are payable in cash and are accounted as part of the production cost. During the second quarter of 2013, the ANH requested the Company to pay in cash royalties related to the condensate from La Creciente field. The Company has completed 92% of the project to increase the process capacity to 100 MMcf/d at La Creciente Station.*
8. *Block Z-1 includes the Corvina and Albacora fields, which are operated by BPZ Resources, Inc, and in which the Company acquired a 49% undivided participating interest on April 27, 2012. The transaction was completed upon the receipt of governmental approval received on December 12, 2012. Under the Operation Services Agreement, the Company has been the technical operations manager since April 1, 2013. The applicable royalties in Peru are paid in cash and are accounted for as part of the production cost.*

Royalties and High-Price Participation

The current royalty rates for volumes of hydrocarbons produced from the Company's Colombian assets range from 5% to 20%. Royalties on production represent the entitlement of the respective states to a portion of the Company's share of production and are recorded using rates in effect under the terms of existing contracts and laws applicable at the time of hydrocarbon discovery. In Colombia, royalties for oil may be payable in kind while royalties for gas are payable in cash. During the second quarter of 2013, the ANH requested the Company to pay in cash the royalties related to the condensate of La Creciente field and the crude oil of minor fields operated by the Company. In Peru, royalty calculations for oil resulted in a 5.3% levy on total gross revenues, which the government allows companies to pay either in kind or cash. However, the current practice is to pay the royalties in cash.

Additional Production Share in the Quifa SW Field

The Company's share of production after royalties in the Quifa SW field is 60%. However, this participation may change monthly as a function of the PAP formula stipulated in the Quifa Association Contract. Starting in April 2013, the Company initiated the delivery of the additional PAP production from the Quifa SW field to Ecopetrol. In addition, during the second half of 2013, the Company agreed to deliver to Ecopetrol approximately 6,500 bbl/d to settle the accumulated PAP prior to the final arbitration decision (previously recorded as a financial provision in the Company's financial statements starting at year-end 2012). During the second half of 2013, a total volume of 1,275 Mbbl was delivered to Ecopetrol. The remaining balance of 452 Mbbl is expected to be fully delivered by March 11, 2014.

Carrizales Field (Cravoviejo Block)

On April 27, 2013, the exploitation area of Carrizales field reached five million barrels of accumulated production of oil, activating the ANH rights on additional production participation share ("**PAP**") due to high prices pursuant to the E&P Cravoviejo contract. According to the contract terms, this additional participation share from Carrizales field is payable either in cash or in kind, and has been accounted for as part of the operating cost for this field. However, the current practice is to pay the royalties in cash.

PAP Disagreement with the ANH

Through various business acquisitions the Company acquired certain exploration contracts where there existed outstanding disagreements with the Agencia Nacional de Hidrocarburos (National Hydrocarbon Agency or "**ANH**" of Colombia) relating to the interpretation of the PAP clause. These contracts require PAP to be paid to the ANH once an exploitation area within a contracted area has cumulatively produced five million or more barrels of oil. The disagreement is around whether the exploitation areas under these contracts should be determined individually or combined with other exploitation areas within the same contracted area, for the purpose of determining the five million barrel threshold. The ANH has interpreted that the high-price participation should be calculated on a combined basis.

The Company disagrees with the ANH's interpretation, and asserts that in accordance with the exploration contracts, the five million barrel threshold should be applied on each of the exploitation areas within a contracted area. One of these contracts is the Corcel Block, which was acquired as part of the Petrominerales acquisition. An arbitration process was initiated by Petrominerales in the prior year, but is currently suspended by mutual agreement. The amount under arbitration was approximately $178 million plus related interest of $70 million as of December 31, 2013. The Company also disagrees with the interest rate that the ANH has used in calculating the interest cost. The Company asserts that since the PAP is denominated in U.S. dollars, the contract requires the interest rate to be three-month LIBOR plus 4%, whereas the ANH has applied the highest legally authorized interest rate on Colombian Peso liabilities, which was over 20%. An amount under discussion with the ANH for another contract is approximately $64 million plus interest.

The Company and the ANH are currently in discussion to further understand the differences in interpretation of these exploration contracts, and expect to resolve these differences within one year. The Company believes that it has a strong position with respect to the PAP based on legal interpretation of the contracts and technical data available. However, in accordance with IFRS 3 on accounting for business acquisitions, the Company is required to and has recorded a liability for such contingencies as of the date of acquisition, even though the Company believes the disagreement will be resolved in favour of the Company. The Company does not disclose the amount recognized on the grounds that this would be prejudicial to the outcome of the dispute resolution.

Update on Environmental Permits

Colombia

In 2013, the Company obtained three environmental licences and amendments for another two. Rubiales and Quifa were modified and Copa, Guama and CPE-6 received new licences. These environmental permits allowed for the oil and gas development in these fields.

The Company received the environmental licences from the Colombian environmental authority, Autoridad Nacional de Licencias Ambientales ("**ANLA**"). The licences are required to advance planned exploration and development activities in both the CPE-6 and Guama E&P blocks.

For 2014, the Company has four licencing processes pending: Cesar Rancheria 1 ("**CR-1**"), Sinu San Jacinto Norte 7 East ("**SSJN-7**"), Cachicamo, and Gasoducto La Creciente Tolú, as well as four modifications of existing licences: Sabanero, Rubiales (irrigation project), Quifa and CPE-6 blocks.

The environmental studies of SSJN-7 and CR-1 are being adjusted in order to comply with additional information requested by the ANLA.

Peru

During 2013, the Company submitted the necessary environmental studies and technical reports to obtain the authorization to initiate an exploratory drilling campaign in the offshore Block Z-1 and in onshore Block 116. The Peruvian authorities have accepted the criteria to relocate the drilling rigs and to modify logistical facilities in order to advance the exploratory drilling project.

Commercial Activity

During 2013, oil and gas sales volumes totaled 134,621 boe/d (108,980 boe/d in 2012), representing an increase of 24% year-over-year, mainly driven by the significant increase in oil production. Oil and gas sales volumes for the fourth quarter of 2013 reached 143,864 boe/d, representing a 20% increase from the volumes reported for the fourth quarter of 2012 (120,141 boe/d in 2012).

The following table highlights the average daily crude oil and gas produced and the trading volume sold as well as the respective realized and international prices:

	Average Volume of Sales (in boe/d)			
	Year ended December 31		Three months ended December 31	
Colombia and Peru	**2013**	**2012**	**Q4 2013**	**Q4 2012**
Oil	120,002	93,141	129,547	107,392
Gas	10,787	10,902	10,918	11,031
Trading	3,832	4,937	3,399	1,718
Total barrels sold (in boe/d)	134,621	108,980	143,864	120,141
Prices				
Oil realized price $/bbl	99.05	102.94	95.54	99.83
Gas realized price $/boe	37.27	42.19	32.69	43.80
Trading realized price $/bbl	101.40	114.62	99.11	100.66
Combined realized price Oil and Gas $/boe (excluding trading)	93.95	96.58	90.66	94.61
WTI NYMEX ($/bbl)	98.05	94.15	97.61	88.23
BRENT ICE ($/bbl)	108.70	111.68	109.35	110.13
Regulated Gas Price ($/MMBTU) (1)	5.81	5.90	5.65	6.04
Henry Hub average Natural Gas Price ($/MMbtu)	3.73	2.83	3.85	3.54

1. *The domestic natural gas sales price is referenced to MRP for gas produced in La Guajira field. The MRP is modified every six months based on the previous half-year variation of the US Gulf Coast Residual Fuel No. 6 1.0% sulphur, Platts.*

Combined oil and gas realized price for 2013 was $93.95/boe, lower by $2.63/boe as compared to that of 2012. In 2013, Colombian crude prices suffered a premium reduction versus WTI, mainly due to the decrease of $6.88/bbl in the ICE Brent - WTI NYMEX differential ($10.65/bbl in 2013 versus $17.53/bbl in 2012).

During the fourth quarter of 2013, combined oil and gas realized price was $90.66/boe, approximately $3.95/boe lower than the same period in 2012. This decrease was due to a wide reduction of $10.16/bbl in the ICE Brent - WTI NYMEX differential ($11.74/bbl in the fourth quarter of 2013 versus $21.90/bbl in the fourth quarter of 2012).

- As indicated in the table above, the Company's combined realized oil and gas price in 2013 was $93.95/bbl; lower by $4.10/bbl than the average market price of WTI NYMEX during the same period.
- During the fourth quarter of 2013, the Company's combined realized oil and gas price was $90.66/bbl, lower by $6.95/bbl than the average WTI NYMEX price as compared to the same period of 2012. This decrease was due to the narrowing of the ICE Brent – WTI NYMEX price differential.
- In 2013, natural gas sales averaged 61.58 MMscf/d, representing a 1% decrease from 62.14 MMscf/d for 2012. Most of the sales were from La Creciente field and averaged $6.62/MMbtu (equivalent to $6.58/Mscf), signifying a premium of 26% over the Guajira fields' weighted price of $5.25/MMbtu and 77% over the Henry Hub natural gas price in the United States.
- For the fourth quarter of 2013, natural gas sales averaged 62.3 MMscf/d, mainly from La Creciente field at an average price of $5.77/MMBtu (equivalent to $5.73/Mscf). This realized price was 25% lower than the fourth quarter of 2012 as a result of the supply contract renegotiation for natural gas for power generation, which was due to the deregulation of the former maximum regulated price of the Guajira field by the Regulatory Commission for Energy and Gas ("**CREG**").

Export Sales Volume

During 2013, the Company sold a total volume of 49.14 MMboe of crude oil and natural gas, of which 44.83 MMbbl of crude oil (91%) corresponded to exports. A breakdown of the crude oil export sales by destination and type of crude is as follows:

	Year Ended December 31		Three Months Ended December 31	
Export by destination	**Volume (MMbbl)**	**%**	**Volume (MMbbl)**	**%**
Asia	12.84	28%	5.82	48%
USA	16.85	38%	2.57	21%
Europe	7.56	17%	1.16	9%
LATAM / Caribbean	7.58	17%	2.65	22%
Total Export	**44.83**	**100%**	**12.20**	**100%**

	Year Ended December 31		Three Months Ended December 31	
Export crude oil reference	**Volume (MMbbl)**	**%**	**Volume (MMbbl)**	**%**
Castilla Blend	29.43	65%	7.73	63%
Vasconia Blend	10.16	23%	3.75	31%
Rubiales	4.87	11%	0.72	6%
Bunkers	0.37	1%	-	0%
Total Export	**44.83**	**100%**	**12.20**	**100%**

Transport of Hydrocarbons

During 2013, the Company transported 151,672 bbl/d through different pipelines and by truck, as follows:

	Year Ended December 31	Three Months Ended December 31
Means of transport	**Volume (bbl/d)**	**Volume (bbl/d)**
ODL-OCENSA pipeline system	81,325	85,995
ODC pipeline	15,479	1,100
ODL and Bicentenario system	3,109	12,333
Trucks	51,759	45,658
Total Transport of Hydrocarbons	**151,672**	**145,086**

In 2013, the Guaduas facility handled 35,978 bbl/d of crude oil volumes including 18,344 bbl/d of third-party, generating an operating profit of $13.5 million.

Reconciliation of Volume Produced vs. Volume Sold

During 2013, net production after royalties and internal consumption in Colombia and Peru totaled 129,326 boe/d (311,177 boe/d total field production), an increase of 32% as compared with figures from 2012. Oil and gas volume sold during the year was 134,621 boe/d compared to 108,980 boe/d for 2012. Oil and gas quantities sold during the fourth quarter of 2013 were 143,880 boe/d, 20% higher as compared to 120,141 boe/d sold in the same period of 2012. This increase was due to rising production volumes in producing fields and the acquisitions of PetroMagdalena, C&C Energia and Petrominerales.

During 2013, a portion of the Company's production was not made available for sale, but rather delivered as follows:

- The Company delivered 1,344 bbl/d of crude oil to Bicentenario pipeline (for a total of approximately 491 Mbbl) in order to meet the Company's share of the line-fill. The pipeline fill was fully completed during the fourth quarter and the costs associated with this operation were capitalized as a fixed asset.

- The Company delivered 3,492 bbl/d to Ecopetrol (for a total of approximately 1,275 Mbbl), as part of the Quifa SW PAP settlement from April 2013. This volume was accounted against the provision originally booked in December 2012. The remaining balance of approximately 452 Mbbl is expected to be delivered by the first quarter of 2014.

A reconciliation of the oil and gas volumes produced and sold during the year and three-month period ending on December 31, 2013 is provided below:

Full Year 2013

Production to total sales reconciliation	Year ended December 31	
	2013	**2012**
Average total field production (boe/d)	311,177	246,575
Net production		
Colombia oil (bbl/d)	117,089	85,123
Colombia gas (boe/d)	10,942	10,961
Peru oil (bbl/d)	1,355	1,573
Total net production (boe/d)	**129,386**	**97,657**
Production available for sale (boe/d)	129,386	96,463
Diluent volumes (bbl/d)	5,085	9,609
Oil for trading volumes (bbl/d)	3,832	4,937
Settlement PAP (bbl/d) (1)	(3,492)	(1,499)
Bicentenario pipeline fill (bbl/d)	(1,344)	-
Inventory movement and other (boe/d)	1,154	(530)
Volumes sold (boe/d)	**134,621**	**108,980**

1. *Corresponds to the inventory delivered to Ecopetrol during 2013. For the fourth quarter, includes the inventory set aside to settle previously accumulated PAP volumes.*

Fourth Quarter 2013

Production to total sales reconciliation	Three months ended December 31	
	2013	**2012**
Average total field production (boe/d)	315,955	271,342
Net production		
Colombia oil (bbl/d)	122,190	95,526
Colombia gas (boe/d)	10,879	11,166
Peru oil (bbl/d)	1,244	1,457
Total net production (boe/d)	**134,313**	**108,149**
Production available for sale (boe/d)	134,313	107,071
Diluent volumes (bbl/d)	2,261	9,671
Oil for trading volumes (bbl/d)	3,399	1,718
Settlement PAP (bbl/d)	(6,363)	-
Bicentenario pipeline fill (bbl/d)	(920)	-
Inventory movement and other (boe/d)	11,174	1,681
Volumes sold (boe/d)	**143,864**	**120,141**

Notes: Refers to full-year 2013 production to total sales reconciliation.

Exploration Activities

During 2013, a total of 34 exploration wells (including stratigraphic and appraisal wells), were drilled, resulting in 23 discoveries, achieving a 68% success rate for the year. This exploration drilling campaign resulted in new discoveries in the CPE-6, Quifa, Sabanero, Arrendajo, Cravoviejo, Cachicamo, Casanare Este, Casimena ,Cubiro, Yamu, La Creciente and Guama blocks in Colombia, in 131 Block Peru, and in the Karoon blocks in Brazil.

During the fourth quarter of 2013, the Company continued with its exploration activities in Colombia, Peru, Brazil, Guatemala, Belize, and Guyana. The exploration drilling campaign in the fourth quarter included 18 exploration wells (including stratigraphic and appraisal wells), 17 of which were drilled in Colombia and one in Peru. In addition, the Company finished the acquisition of 12,500 km of 2D seismic in Guyana and 2,361 km of aeromagnetic and aerogravimetric survey data in Colombia. The drilling results for the year and three-month period ending December 31, 2013 and 2012 are as follows:

	Year Ended December 31		Three Months Ended December 31	
	2013	2012	2013	2012
Successful exploratory wells	15	3	5	2
Successful appraisal wells (1)	7	34	6	1
Successful stratigraphic wells	1	7	1	-
Dry wells	11	11	6	3
Total (see breakdown in the table below)	**34**	**55**	**18**	**6**
Success rate	**68%**	**80%**	**67%**	**50%**

1. Includes horizontal appraisal wells.

Details of Exploratory and Appraisal Wells Drilled During the Fourth Quarter of 2013

The following is a summary of the exploration drilling campaign during the fourth quarter of 2013:

No. of wells	Country	Block	Area / Field / Prospect	Well Name	Type	Total Depth MD (feet)	Net Pay (feet) (1)
1	Colombia	CPE-6	Hamaca	CPE-6-1X	Exploratory	3,318	50
2	Colombia	CPE-6	Hamaca	CPE6-H2	Appraisal	3,317	34
3	Colombia	Quifa	QFN-D	QFN-D-1X	Exploratory	4,235	21
4	Colombia	Quifa	QFE-A	QFE-A-1XST	Exploratory	4,699	-
5	Colombia	Quifa	QFN-C	QFN-C-1X	Exploratory	4,437	-
6	Colombia	CPO-14	CPO-14-A	CPO-14-STRAT-2	Stratigraphic	2,696	1
7	Colombia	Sabanero	Sabanero-SW2	Sab-Strat-SW-2	Stratigraphic	3,344	1.5
8	Colombia	Cachicamo	Falco	Falco-1	Exploratory	8,304	-
9	Colombia	Cachicamo	X-Ray	X-Ray 1	Exploratory	7,922	15
10	Colombia	Cravoviejo	Gemar	Gemar 2	Appraisal	9,425	9
11	Colombia	La Creciente	La Creciente "H"	LCH-1X	Exploratory	11,552	69
12	Colombia	Portofino	Tachuelo	Tachuelo-1	Stratigraphic	2,462	-
13	Colombia	Casanare Este	Curito	Curito-2	Appraisal	10,201	16
14	Colombia	Casanare Este	Curito	Curito-3	Appraisal	10,421	8
15	Colombia	Casimena	Pisingo	Pisingo-2	Appraisal	8,557	34
16	Colombia	Castor	Capybara	Capybara-3	Appraisal	12,150	-
17	Colombia	Rio Ariari	Mochelo	Mochelo sur -1HZ	Appraisal	5,095	2,984
18	Peru	Block 131	Los Angeles	Los Angeles 1X	Exploratory	12,409	57

1. *"Net Pay" represents the total estimated net pay encountered in the horizontal or vertical drilled sections.*

Colombia

On November 2, 2013, the Company was granted a global environmental licence for the northern part of the CPE-6 Block. After receiving the licence, the Company drilled the CPE-6-1X exploration well and the CPE6H-2 appraisal well. The CPE-6-1X exploration well was drilled to a total depth of 3,318 feet in the Hamaca prospect targeting the Basal Sand Unit of the Carbonera Formation. The petrophysical evaluation of the well indicated a total of 50 feet of net pay averaging 30% porosity across a gross interval of 90 feet. The well was completed in the net pay interval and tested at an average flow rate of 222 bbl/d of 10.8 °API with 15% water cut by year-end.

The CPE-6-H2 appraisal well was drilled 3.8 km northeast of the CPE-6-1X well. The petrophysical evaluation showed 35 feet of net pay in the Basal Sand Unit, confirming the extension for the reservoir in this direction. The well was tested at a flow rate of 213 bbl/d of 10.9 °API oil with a 12% water cut.

Based on the successful results of these two wells, the Company submitted to the ANH the evaluation plan for the Hamaca prospect, which would allow drilling of additional appraisal wells to delineate the reservoir and to carry extended tests in all the wells. This will support the documentation for the declaration of commerciality. With the drilling of the CPE-6-1X exploration well, the Company has fulfilled the work commitments for the first phase of this E&P contract.

In the Quifa Block, the Company drilled three exploration wells and continued with the acquisition of 721 km^2 of 3D seismic survey in the northwestern portion of the block. The QFN-D-1X exploration well located in the QFN-D prospect of northern Quifa showed 21 feet of net pay and is considered to be a new oil discovery for this prospect. At this time, the well is under an extended production test. This well, together with QFE-S-1X, which was drilled during the third quarter of 2013, confirms the hydrocarbon potential in these areas. The Company is currently preparing an appraisal drilling campaign to evaluate and confirm the extension of these discoveries.

The QFE-A-1XST and QFN-C-1X exploration wells were drilled in the prospects QFE-A and QFN-C in eastern and northern Quifa respectively. Both wells had some hydrocarbon show during drilling, but the wells' petrophysical evaluations did not indicate any commercial intervals so the wells were plugged and abandoned.

In the Sabanero Block, the Company drilled the Sab-Strat-SW2 stratigraphic well located in the southwestern part of the block. Although the well only showed 2.5 feet of hydrocarbon column, the results indicated a possible prospectivity to this part of the block. As a result, the Company is evaluating the possibility of drilling additional wells to evaluate this area.

In the southwestern part of the CPO-14 Block, the Company drilled the first stratigraphic well and continued with the acquisition of 251 km of 2D seismic as part of the exploration commitments for the first phase of the contract. The CPO-14-Strat-2 only showed 1.5 feet of hydrocarbon column in the Basal Sand Unit so the well was plugged and abandoned.

In the Cachicamo Block of the Eastern Llanos Basin, two exploration wells were drilled. The Falco-1 well reached a TD of 8,304 feet in the Ubaque Formation, but the well found no pay and was plugged and abandoned. The X-Ray-1 well reached TD at 7,922 feet in the Ubaque Formation. The well found 15 feet of net pay in the Gacheta Formation. It was completed with an initial production of 90 bbl/d and a water cut of 40%.

In the Cravoviejo Block, the Gemar-2 well reached TD at 9,300 feet. The well found five and four feet of potential pay in the Gacheta and the Carbonera C5 formations, respectively. The well was completed in the C5 sand and produced 395 bbl/d on pump with a water cut of 8%.

In the Casanare Este Block, the Company drilled two appraisal wells in the Curito discovery. The Curito-2 well was drilled to a TD of 10,201 feet, and petrophysical evaluation indicated 16.4 feet of net pay in the C7. The well was completed in the C7 Formation and has produced an average of 1,903 bbl/d of 34.5 °API oil with an average water cut of 36%. The Curito-3 well was drilled to a TD of 10,421 feet. Petrophysical evaluation indicated 7.7 feet of net pay in the C7 Formation. The well was completed in the C7 formation and since November 18, 2013 has produced an average of 2,685 bbl/d of 34.5 °API oil with an average water cut of 21%.

In the Casimena Block, the Pisingo-2 appraisal well was directionally drilled to a depth of 8,557 feet. Petrophysical evaluation indicated 35 feet of net pay consisting of 22 feet net pay in the C7 Formation and 13 feet net pay in the Mirador Formation. The well was completed in both the C7 and Mirador formations.

In the Castor Block, the Capybara-3 appraisal well was drilled to a total depth of 12,150 feet. The C7 target was encountered at the same elevation as the nearby Capybara-2 well, however, the reservoir sands that produced oil at Capybara-2 were not present in the well. One C7 sand was tested and produced water with a trace of oil. A second C7 sand will be tested using a completion rig in early 2014. All other secondary zones had poor oil shows.

In the Canaguaro Block, the Company started drilling operations of the Canaguary-2 appraisal well in November 2013. Due to operational issues, the Company did a sidetrack to the original hole and the well is currently drilling at 13,013 feet in the C4. The well is expected to reach TD during the first quarter of 2014.

In the Rio Ariari Block, the Mochelo Sur-1HZ well was drilled to a vertical depth of 5,095 feet and with a 3,004-foot horizontal leg. The well was open-hole completed and has initially tested at rates over 400 bbl/d of 9 °API oil. The well is waiting on results from other wells in the area to decide on further extended testing using a higher volume electrical submersible pump.

In the Guama Block, in the Lower Magdalena Valley Basin, the Company carried out the planned stimulation and tests on CAPURE-1X well, obtaining after-frac gas condensate and oil from three zones in the Miocene Porquero sand reservoir, which resulted in the fourth discovery in the area.

In the La Creciente Block, also in the Lower Magdalena Basin, the exploration well LCH-1X reached TD of 11,552 feet in early November. The well, drilled on the “H” prospect, flowed gas at rates less than 2 MMcf/d from the Ciénaga de Oro sands. A subsequent sidetrack, directionally drilled to investigate the western flank of the new “H” discovery, was in progress by December 31.

Also in the La Creciente Block, the LCI-1XST exploration well produced 9.4 MMcf/d on short-term tests through a 18/6 inch choke in the Ciénaga de Oro sands, thus confirming the prospect “I” gas discovery. A subsequent test of Porquero Medio sands tested wet. The well was completed as a suspended gas producer, waiting on tie-in to the La Creciente facilities.

In the Portofino Block, the block operator Canacol Energy Ltd. drilled the Tachuelo-1 stratigraphic well. The well reached TD at 2,462 feet on December 8, and recovered a core of 122 feet. The well did not show the presence of a hydrocarbon column in the evaluated intervals, so the well was plugged and abandoned.

In the Caguan-5 and Caguan-6 Blocks in the Putumayo Basin, 2,361 km of aeromagnetic and aerogravimetric surveys were completed. The data interpretation is under way.

In the COR-24 Block, the Company completed and delivered the information required by the local environmental authority in order to obtain the environmental permits for a 2D seismic project. The permit was awarded in early December, and 305 km of planned 2D seismic survey will commence during the first quarter of 2014.

In the COR-15 TEA Block, the block operator Maurel & Prom Colombia B.V. is waiting on the approval from the ANH to convert the TEA into an E&P contract.

In the Muisca Block, the block operator Maurel & Prom Colombia B.V. spudded the Balsa-1X exploration well in early December. The well drilling operation is expected to be completed during the first quarter of 2014.

Peru

In February 2014, the Company announced a significant light oil discovery in Block 131 and also provided an update on the discovery in Block 126, both acquired as part of the Petrominerales acquisition. In Block 131, the Company finished drilling the Los Angeles 1X exploration well, which reached a total depth of 12,409 feet on November 25, 2013. Petrophysical evaluation indicated the presence of 62 feet of pay in the Cushabatay formation. The discoveries are being processed, and support our confidence on the potential of the under-explored onshore basins in Peru.

In Block 116 in the Santiago Basin of northern Peru, the Company finished the river-bound move of the drilling rig to the Fortuna–1X well site. The well is targeting potential limestone and sandstone reservoirs in the Cretaceous with a planned TD of 12,659 feet. At year–end, the well was starting to rig-up and is expected to spud during the first quarter of 2014.

In Block 138, the Yahuish-1X exploration well remains in a suspended operations status, with the inconclusive testing results under evaluation.

In Block Z-1, located in the offshore Tumbes Basin of northern Peru, the Company finished the processing of 1,542 km^2 of 3D seismic data acquired in 2012. In addition, during the period, two exploration wells were approved for drilling for the first half of 2014. The Company continued with the corresponding environmental permit process in the central and southern areas that cover approximately 70% of the entire block.

Guatemala

In the Guatemala blocks (N-10-96 and O-10-96), the block operator Compañía Petrolera del Atlántico S.A. ("**CPA**") continued drilling the Balam-1X exploration well with the Cretaceous Cobán Formation as the main exploration objective. On December 31, the rig was drilling the 8.5-inch hole section at 14,360 feet. The well is expected to finish drilling operations during the first quarter of 2014.

Belize

In Belize, the Company completed the contracting of the 650-km 2D survey. Also, contracting activities for surface geology, sample analysis and surface geochemistry are also under way. The Company acquired 2,500 km of aeromagnetic and aerogravity data. The EIA (for restricted areas within the seismic survey coverage) is 60% progressed and is expected to be completed during the first quarter of 2014.

Brazil

In December, the Agencia Nacional do Petróleo Gás Natural e Biocombustíveis ("**ANP**") approved the Evaluation Plan for the Kangaroo discovery (Plano de Avaliação de Descoberta do Poço 1-KPGL-1D-SPS). The Evaluation Plan includes an appraisal of the Kangaroo discovery as well as an exploration well to test a satellite trap west of Kangaroo. The Operator, Karoon Petróleo & Gás Ltda., expects to commence drilling during the second half of 2014, subject to rig availability. Two confirmed wells are planned, including an up-dip appraisal of the 2013 Kangaroo-1 discovery and an exploration well on the undrilled Kangaroo West prospect.

Guyana

Through CGX Energy, Pacific Rubiales has rights to three exploration licences in the Guyana Basin (two offshore blocks, Corentyne & Demerara, and one onshore block, Berbice) spanning 13,500 km^2 in a large highly, potential frontier basin. During the quarter, 3,500 km^2 3D seismic data were reprocessed. This data will be used to evaluate the prospectivity of the three licence areas and to select locations for three exploration wells, which form part of the licence contract commitment. The first well is expected to be spudded no later than the first quarter of 2015 on assignment of a suitable drilling rig.

5. Capital Expenditures

Excluding acquisition costs, capital expenditures during 2013 totaled $2,066 million (compared to $1,548 million in 2012). A total of $644 million was invested in the expansion and construction of production infrastructure, primarily in Quifa SW, Block Z-1, Cajua and in the Rubiales fields; $593 million went into exploration activities including drilling, seismic and other geophysical activities in Colombia, Peru, Brazil, Guatemala, Belize, and Guyana; $26 million went into early facilities and others; $629 million went into development drilling; and $174 million was invested in other projects including the STAR project at Quifa SW. Details of capital expenditures for the year and three-month periods ending December 31, 2013 and 2012 are as follows:

	Year Ended December 31		Three Months Ended December 31	
(in thousands of US$)	**2013**	**2012**	**2013**	**2012**
Production facilities [(1)]	$ 644,062	$ 594,819	$ 202,677	$ 238,606
Exploration activities [(2)]	593,023	355,446	145,123	139,250
Early facilities and others	26,367	134,473	26,367	31,160
Development drilling [(1)]	628,745	347,308	183,688	139,221
Other projects (STAR, Gas export, PEL)	173,328	116,150	67,543	53,119
Total capital expenditures	**$ 2,065,525**	**$ 1,548,196**	**$ 625,398**	**$ 601,356**

1. *Includes investment in Maurel & Prom Colombia B.V., in which the Company holds a 49.999% participation and through whom the Company indirectly owns a 100% working interest in the Sabanero Block.*
2. *Exploration activities for the fourth quarter of 2013 include drilling, seismic and other geophysical expenditures in Colombia, Peru, Brazil, Guatemala, Belize and Guyana.*

The following table shows the capital expenditures on acquisitions executed during 2013.

	Year Ended December 31		Three Months Ended December 31	
(in thousands of US$)	**2013**	**2012**	**2013**	**2012**
Petrominerales (Colombia - Peru)	1,000,341	-	1,000,341	-
Farm-in Agreement and others [(3)]	133,181	367,920	20,134	125,000
C&C Energia Ltd. (Colombia)	-	533,647	-	533,647
PetroMagdalena (Colombia)	-	226,598	-	-
Total capital expenditures for new acquisitions	**1,133,522**	**1,128,165**	**1,020,475**	**658,647**

3. *Includes block acquisition costs in Brazil, Peru and Papua New Guinea.*

6. Proved and Probable Oil and Gas Reserves

For the year ending December 31, 2013, the Company received independent certified reserves evaluation reports for all of its assets establishing that total net 2P reserves had grown to 619.2 MMboe from 513.7 MMboe, a 21% year-on-year growth. This growth represents a 314% reserve replacement with net 2P reserve additions of 3.14 boe-per-boe produced. 1P reserves of 394.1 MMboe now represent 64% of the total 2P reserves; a growth of 17% when compared to the same period of 2012. The 1P reserves represent 1.22 boe per outstanding share (compared to 1.05 per share on December 31, 2012). The Company's RLI decreased slightly to 13 from 14. Approximately 81% of net 2P reserves are liquid hydrocarbons with the majority of these being heavy oil.

Significant reserves additions resulted from acquisitions (totaling 89 MMboe), including first reserves bookings and production in onshore Colombia from Petrominerales acquisition. At year-end 2013, the Rubiales field represented less than 11% of total 2P reserves, demonstrating successful diversification of the Company's reserve base.

The following tables summarize information contained in the independent-reserves reports prepared by RPS Energy Canada Ltd. (“**RPS**”) dated February 14, 2014; Petrotech Engineering Ltd. (“**Petrotech**”) dated February 28, 2014; Netherland, Sewell & Associates, Inc. (“**NSAI**”) dated January 31, 2014; and Degolyer and MacNaughton Limited (“**D&M**”) dated February 17, 2014. All the reports had an effective date of December 31, 2013. RPS evaluated the reserves of the Company in the developed Rubiales and Quifa SW heavy oil fields, Petrotech evaluated the reserves in the remaining oil and gas fields in Colombia and the natural gas reserves in the Block Z-1 in Peru. NSAI evaluated the oil reserves in the Block Z-1 in Peru and D&M evaluated the majority of the developed oil fields acquired from the 2013 acquisition of Petrominerales. These reports were prepared in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook (“**COGE Handbook**”) and the National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* (“**NI 51-101**”).

Reserves at December 31, 2013 (MMboe [(1)])											
Country	**Field**	**Total Proved (1P)**			**Probable (P2)**			**Proved Plus Probable (2P)**			**Hydrocarbon Type**
		100%	**Gross**	**Net**	**100%**	**Gross**	**Net**	**100%**	**Gross**	**Net**	
Colombia	Rubiales	197.8	83.5	66.8	-	-	-	197.8	83.5	66.8	Heavy Oil
	Quifa SW	133.8	80.3	64.8	11.8	7.1	5.8	145.6	87.3	70.5	Heavy Oil
	CPE-6	34.1	17.0	15.6	104.5	52.3	47.3	138.6	69.3	62.9	Heavy Oil
	Rio Ariari [(2)]	10.3	10.3	9.7	35.7	35.7	33.5	46.1	46.1	43.2	Heavy Oil
	Other Heavy Oil Blocks [(3)]	99.3	69.5	58.2	76.6	48.3	39.8	175.9	117.8	98.0	Heavy Oil
	Petrominerales Blocks [(4)]	49.5	32.0	28.4	27.7	19.6	17.5	77.2	51.6	45.9	Light & Medium Oil
	Other Light Oil Blocks [(5)]	47.7	34.4	29.7	17.6	11.4	9.6	65.3	45.8	39.4	Light & Medium Oil Associated Natural Gas
	Natural Gas Blocks [(6)]	107.2	107.2	100.2	20.5	20.5	19.2	127.6	127.6	119.3	Natural Gas
	Sub-total	**679.6**	**434.1**	**373.3**	**294.4**	**194.8**	**172.6**	**974.0**	**629.0**	**546.0**	Oil & Natural Gas
Peru	Block Z-1	42.7	20.8	20.8	106.6	52.2	52.4	149.3	73.0	73.2	Light & Medium Oil, Natural Gas
	Total at Dec. 31, 2013	**722.3**	**454.9**	**394.1**	**400.9**	**247.1**	**225.1**	**1,123.3**	**702.0**	**619.2**	Oil & Natural Gas
	Total at Dec. 31, 2012	670.4	389.8	335.5	373.9	209.8	178.2	1,044.4	599.6	513.7	
	Difference	51.9	65.2	58.6	27.0	37.2	46.9	78.9	102.4	105.5	
	2013 Production	113.6	57.7	47.2	**Total Reserves Incorporated**			192.4	160.1	152.7	

(1) The term ''boe'' is expressed herein using the Colombian conversion standard of 5.7 Mcf: 1 bbl required by the Colombian Ministry of Mines and Energy and 6 Mcf: 1bbl for the Company's Peru reserves.

(2) Heavy oil Petrominerales block, acquired in 2013 (no prior reserve bookings).

(3) Includes Cajua, Quifa North and Sabanero properties.

(4) Light and medium oil on Petrominerales Blocks acquired in 2013 (excluding the heavy oil Rio Ariari Block).

(5) All other light- oil properties (excluding Petrominerales acquisition).

(6) Includes La Creciente and Guama properties.

(7) Total net 2P reserves, expressed in boe, increased slightly from that previously announced, as result of a small non-material movement from roylaties paid in kind to paid in cash.

In the table above, 100% refers to total 100% field interest; Gross refers to WI before royalties; Net refers to WI after royalties; Numbers in table may not add due to rounding differences.

All additional reserves information as required under NI 51-101 will be included in the Company's Annual Information Form dated March 13, 2014.

7. Farm-in Transactions and Acquistions

The following is a summary of the farm-in transactions and acquisitions completed during the fourth quarter of 2013.

Petrominerales Acquisition

On September 29, 2013, the Company announced that it had entered into an arrangement agreement with Petrominerales to acquire all of the issued and outstanding common shares of Petrominerales, under which Petrominerales' shareholders received C$11.00 cash for each Petrominerales common share held, plus one common share of a newly formed exploration and production company called Alvopetro, whose portfolio consists of the Petrominerales' former Brazilian exploration assets.

The total purchase price on a fully diluted basis, including assumed net debt and excluding funding of Alvopetro, was approximately C$1.6 billion. Financing of the acquisition was accomplished by cash on hand, existing bank credit facilities and the issuance and reopening of bonds for approximately $1.3 billion. The transaction was completed on November 28, 2013 with the approval of the shareholders of Petrominerales, a Canadian court simply state under the Investment Canada Act and regulatory approvals.

The arrangement resulted in the acquisition of approximately 9.8 million gross (6.8 million net) acres of exploration and development properties in Colombia (18 blocks) and Peru (four blocks), as well as oil pipeline interests in Colombia and associated transportation capacity (5% in OCENSA and 9.65% in Bicentenario). The assets acquired have certified 2P gross reserves of 123.2 MMbbl (89.0 MMbbl net) as at year-end 2013, and produced approximately 26 Mbbl/d gross in 2013.

This acquisition provided immediate capture of additional value through asset synergies, and provides additional production, reserves and cash flow for the Company. The Petrominerales light oil and pipeline assets in Colombia provide a strategic hedge for our future supply, cost and security of diluent volumes and pipeline transportation, based on our expectation of the Company's growing heavy oil production. It has also provided the Company with reliable transportation infrastructure by way of Petrominerales' interests in the OCENSA (5% interest) and Bicentenario (9.65% interest) oil pipelines in Colombia, which are highly strategic to the Company's plans to increase its heavy oil production in the country.

On December 20, 2013, the Company reached an agreement to sell the 5% equity ownership and transportation rights in OCENSA for a total cash consideration of $385 million while retaining a long-term agreement for transportation of the Company's oil production in this strategic pipeline. The transaction is expected to close during the first quarter of 2014.

C$35 Million to Acquire Control of CGX

On April 26, 2013, the Company closed the acquisition of 350 million units of CGX at C$0.10 per unit for C$35 million under a private placement, pursuant to the binding term sheet that was previously signed. Under the private placement, each unit consists of one common share of CGX and one share purchase warrant, exercisable for a five-year period at C$0.17 per share. The investment increases the Company's interest in CGX to approximately 63%, effectively acquiring control of CGX.

Through this transaction the Company increased its foothold in world-class exploration assets in the Guyana-Suriname basin. On the Corentyne Block specifically, the certifier D&M estimated mean Prospective Resources of 1,522 MMbbl of liquid hydrocarbons and 7,889 Bcf of natural gas (resource report dated December 31, 2012).

New Exploration Blocks Awarded in Brazil

The ANP awarded the Company three blocks during Brazil's 11th Bid Round. The Company's working interest in the blocks ranges from 30% to 70%.The awarded blocks are located in the Foz do Amazonas Basin (one block) and in the Pará-Maranhão Basin (two blocks) in northern deep-water offshore Brazil, and have a total area of approximately 2,300 km^2 gross (1,153 km^2 net). The two blocks in the Pará-Maranhão Basin were acquired through a consortium with Queiroz Galvão Exploração e Produção S.A., and the block in the Foz do Amazonas Basin was acquired through a consortium with Queiroz Galvão Exploração e Produção S.A. and Premier Oil Plc. All three blocks are operated by Queiroz Galvão Exploração e Produção S.A. and have an initial five-year exploration phase with the option to extend this phase by three additional years.

Approval of Participating Interest in Brazil

On September 11, 2013, the ANP approved the acquisition of a 35% participating interest by the Company in the exploration contracts for Blocks S-M-1101, S-M-1102, S-M-1037, and S-M-1165, and on December 18, 2013 for Block S-M-1166. All of the blocks are located off-shore in the Santos basin of Brazil. The Company first announced this acquisition on September 18, 2012, when it executed the corresponding farm-in agreement with Karoon Petróleo & Gas Ltda. The contingent resources in Kangaroo field are 633 MMbbl and the prospective resources are 909 MMbbl.

Acquisition of Interest in Belize

On February 15, 2013, the Company acquired from several private investors a 100% equity interest in the company BCH International Inc., which holds the La Democracia block (previously known as Blocks 6 and 15) located in Belize for a total of $1.5 million in cash and an overriding royalty; 10% of the shares of BCH International Inc. are held in escrow and will be delivered to PRE two years after closing of the transaction. La Democracia block is operated under a Production Sharing Agreement and is located in the central part of Belize with a total area of 638,520 acres. The Company is targeting new exploration and development opportunities similar to those identified in the Caribbean trend and the Yucatan Province.

Approval of Participating Interest in Peru

On June 27, 2013, the Peruvian government approved the acquisition of a 50% participating interest by the Company in the exploration contract for Block 116 located in northeastern Peru as well as the transfer of the operatorship of this block to the Company. Following regulatory approval, the Company has initiated preparations for an exploratory well in the Block and is planning to start in early 2014.

Approval of Participating Interest in Papua New Guinea

In 2012, the Company entered into an agreement with InterOil Corporation to acquire a 10% net participating interest in the PPL237 Petroleum Prospecting Licence and the Triceratops structure located within PPL237 in Papua New Guinea for an estimated total investment of $345 million. The investment is comprised of an upfront payment of $116 million (which has been fulfilled), funding of an agreed exploration work program and cash payments based on independently certified resources of the Triceratops structure.

On January 24, 2013, the Minister of Petroleum & Energy approved the acquisition of the participating interest by the Company in the Petroleum Prospective Licence PPL237. On December 4, 2013, the same Ministry granted the Petroleum Retention Licence PRL-39, which had been previously requested by all parties to the PPL237 with respect to the Triceratops structure.

Approval of Participating Interest in Sabanero Field

On September 6, 2013, the Company and Maurel & Prom Colombia B.V. signed a purchase and sale agreement by which the Company acquired a 100% participating interest in the Sabanero block. This transaction was approved by the ANH on December 26, 2013.

8. Project Status

Following is an update on the current status and working-interest share of costs incurred to date for the Company's major projects:

Project	Project financed by	As of December 31, 2013 Total cost to complete the project	Cost incurred to date	Expected future costs to incur
STAR project in the Quifa field	Internally generated funds	$ 165,000	$ 142,127	$ 22,873
Cusiana blending facility	Equity and debt combination	17,000	17,000	-
Bicentenario pipeline	Equity and debt combination	579,609	130,000	449,609
PEL-Power transmission line project	Equity and debt combination	220,000	159,656	60,344
Small-scale LNG project	Equity and debt combination	180,000	25,914	154,086
Water treatment for agricultural development	Equity and debt combination	170,000	69,987	100,013
Puerto Bahia Project	Equity and debt combination	366,390	240,000	126,390
CX15 - Platform Pacific Stratus Perú	Equity and debt combination	96,000	95,000	1,000
		$ 1,793,999	**$ 879,684**	**$ 914,315**

STAR Project in the Quifa SW Field

In March 2011, the Company and its partner Ecopetrol agreed to carry out a pilot project using the STAR technology, covering an area of approximately 20 acres in the Quifa SW field as a preliminary step to expanding the technology to a commercial level. The pilot project followed two years of extensive laboratory testing and simulation. STAR is aimed at significantly increasing recovery in the Company's heavy oil fields in Colombia, which under primary flow, only results in a 14% to 16% recovery of the Original Oil in Place ("**OOIP**"), leaving behind the remaining oil in the ground.

During 2012, the pilot facility was constructed, production and injection wells were drilled, compression and production equipment was installed, and preliminary equipment and injection testing was conducted. Air injection and thermal ignition of the reservoir were initiated in February 2013 and have been sustained throughout the year, along with demonstrated synchronized control of the thermal front and the producing wells.

During the third quarter of 2013, the Company received reports from three independent engineering firms on the progress of the pilot project and their estimate of the OOIP for the project area. These estimates, combined with the cumulative oil production from the pilot project, allow the Company to estimate that at least a doubling of the recovery factor has been achieved to date since commencement of air injection in February 2013.

Also in the third quarter, the Colombian patent authority, SIC, granted the Company two patents for its proprietary STAR enhanced oil-recovery technology. These patent awards provide the Company with intellectual property rights to the STAR technology in Colombia for an exclusive 20-year period from the filing date of April 1, 2011 until April 1, 2031.

Based on the pilot results, the Company plans on semi-commercial rollout of STAR in Quifa SW by converting two or three contiguous well clusters in the pilot test area, which are currently producing on primary flow to STAR, as a first stage of a commercial project. At the end of 2013, all production facilities were in place and flow lines from contiguous wells were operational. The production capacity installed is 20 Mbbl/d total fluid.

Cusiana Blending Facility

This facility allows for the blending of light oil, which is trucked to a new diluent blending facility at the OCENSA pumping station located in Cusiana, with heavy oil pumped through the ODL Pipeline. As a result, the API gravity in the ODL Pipeline may be reduced from 18° to 15°, resulting in significant savings in diluent transportation costs. The project was completed during the second quarter of 2013 and blending started on April 22, 2013. By December 2013, the Cusiana facility had processed approximately 2.3 MMbbl of diluent and had pumped approximately 43.4 MMbbl of diluted crude oil to the OCENSA pipeline. This operation has contributed to a significant reduction in transportation and blending costs of the Company.

Bicentenario Pipeline

The Company has a 43.03% equity interest in the Bicentenario pipeline, including the Petrominerales recent acquisition. Bicentenario is a special-purpose entity promoted by Ecopetrol, who has a 55.97% interest in the company with the remaining 1% interest owned by other oil producers operating in Colombia. Bicentenario is responsible for the financing, design, construction and operation of the Bicentenario Pipeline, Colombia's newest oil pipeline transportation system, which runs from Araguaney in the Casanare Department of central Colombia to the Coveñas Export Terminal in the Caribbean.

As at December 2013, Phase 1, which comprises a 230-km, 42-inch pipeline from Araguaney to Banadía, had reached mechanical completion. Line fill ended on October 3, 2013, with a total of approximately 1.2 MMbbl. In the Coveñas terminal, two tanks with a total capacity of 600 Mbbl were ready for manual operation and the overall construction progress for Phase 1 reached 88.7%. As at the end of December 2013, approximately 3.4 MMbbl had been pumped through the system.

The startup of the Bicentenario Pipeline is an important milestone in reducing the Company's crude oil transportation costs.

PEL – Power Transmission Line Project

Petroelectrica ("**PEL**") is a wholly owned subsidiary of the Company and is responsible for constructing and operating a new power transmission line of 230 kilovolts that connects the Rubiales field with Colombia's electrical grid. The new transmission line originates at the Chivor Substation and stretches 260 km to the Rubiales field. The project includes two substations (Jagüey and Corocora) to supply power to the booster stations of the ODL Pipeline, as well as substations for the Rubiales and Quifa fields. The new power line will be able to supply up to 192 MVA that will be used in oil production and pipeline transportation activities. The PEL transmission line will help to reduce the operating costs for the Rubiales and Quifa fields by lowering electricity costs for oil production and transportation.

As at December 2013, the power transmission line and the Rubiales substation achieved mechanical completion. The Quifa substation reached a progress of 41%. In the last quarter of 2013, ANLA granted an environmental licence for substations Jagüey and Corocora. The energizing of the power line took place on January 20, 2014.

Small-Scale LNG Project

The Company is actively looking for alternate ways to monetize its existing natural gas reserves in the La Creciente and Guama fields as well as exploit its other extensive gas exploration resources in nearby fields. The Company has initiated a small-scale liquefied natural gas project that is being developed jointly with Exmar NV ("**Exmar**"), an experienced LNG/LPG transportation company based in Belgium. The project is targeting LNG supply FOB from Colombia.

The project comprises an 88-km, 18-inch gas pipeline from La Creciente Gas Field to the Colombian Atlantic Coast and a Floating, Liquefying, Regasification and Storage Unit ("**FLRSU**"). The FLRSU will be connected to a Floating Storage Unit ("**FSU**") in order to allow FOB exports to standard carriers (130,000 to 150,000 CBM).

In March 2012, the Company signed a tolling agreement with Exmar. Under the terms of this agreement, the first natural gas liquefaction is targeted for the first half of 2015. Environmental permits for the onshore portion of the gas pipeline are in place. Construction of the FLRSU is underway in WISON´s shipyard in China.

In November, the Company and GAZPROM announced the execution of a Heads of Agreement for the negotiation of a five-year Sale and Purchase Agreement for approximately 0.5 million tons per year of liquefied natural gas FOB Colombia (Caribbean Sea) beginning in the second quarter of 2015.

As at December 2013, basic and detailed engineering for the gas pipeline and the offshore jetty was 97% complete. Port concession for the LNG terminal was granted, pending environmental licencing permits for the subsea line. As of the date of this report, the process to select the EPC contractor is ongoing and purchase orders for long-lead items have been placed, including one for the pipeline.

Water Treatment for Agricultural Development

In order to handle the increasing volume of water produced in the Rubiales and Quifa fields, the Company has initiated a project to treat produced formation water from these fields and use it for irrigation purposes in a neighboring palm oil agricultural project for biodiesel manufacturing. The first phase of this project includes the construction of two water treatment plants using Reverse Osmosis ("**RO**") technology, each with a capacity of 500,000 bbl/d. This project will bring significant savings in terms of energy and capital expenditures compared to current disposal. In addition, the palm oil project will create sustainable jobs and social development for the area.

As of December 2013, the following is in progress:

- Construction of the RO Plant had reached 55% of completion.
- 1,300 ha of palm trees have been seeded. Applications for environmental permits to allow the use of produced water for agricultural use have been initiated.

Pacific Infrastructure: Puerto Bahía Terminal and Olecar Pipeline

As at December 31, 2013, the Company had a 41.6% interest in Pacific Infrastructure, a private company that is currently developing Puerto Bahía, an oil export terminal located in Cartagena Bay in Colombia. Puerto Bahía will be developed in three phases: (i) 1.7 MMbbl of oil and petroleum product storage capacity, a berthing position for vessels of up to 80K DWT, a truck loading and unloading station with a capacity of up to 30 Mbbl/d and a fixed bridge; (ii) additional storage capacity of up to 3 MMbbl, an additional berthing position for vessels of up to 150K DWT and barge handling facilities with a capacity of up to 45 Mbbl/d; and (iii) a liquids terminal with capacity of up to 4 MMbbl, a multi-purpose terminal handling bulk materials, containers and a berthing platform with a length of 300 metres to handle dry materials.

During 2012, the environmental licence, the port concession and the free-trade zone permits were granted. Designs and engineering were completed during the first half of 2013. As at December 31, 2013, construction of Phase 1 reached 37.6% completion.

Recognizing the strategic importance of Puerto Bahía Terminal, Pacific Infrastructure signed an O&M agreement with Oiltanking International. Oiltanking is recognized globally as a world-class operator of large-scale liquids terminals. Signature of the credit agreement with Itau bank for $370 million took place during the last quarter of 2013. Financial close is expected for the first quarter of 2014.

In addition to Puerto Bahía, Pacific Infrastructure is also developing the Olecar pipeline, which will connect Puerto Bahía to the oil pipeline hub at the port of Coveñas, ensuring the uninterrupted supply of crude oil for export. The Olecar project includes: (i) a pumping station at Coveñas with a capacity of 300 Mbbl/d; (ii) a 130-km, 30-inch diameter pipeline; and (iii) bidirectional connections between the Cartagena Refinery, the second largest refinery in Colombia, and Puerto Bahía.

As of the date of this report, environmental permits for the Olecar pipeline have been granted by ANLA and right-of-way negotiations are in progress. Long-lead items' purchase orders have been placed, including pipe and main pumps. CONCOCAR Consortium has been selected as the EPC Company. The project is currently 18% completed.

New Partners in Pacific Infrastructure

During the fourth quarter of 2013, International Finance Corporation ("**IFC**"), a member of the World Bank Group, and two funds managed by an IFC associate invested a combined $150 million for a 27.2% interest in the equity of Pacific Infrastructure. Upon the investment by IFC, the Company's interest was diluted to 41.6% from 56.9% and the Company recorded a gain of approximately $48 million. The investment by IFC is a testament to the vision and strategic importance of the Puerto Bahía Terminal and the Olecar Pipeline.

9. Discussion of 2013 Financial Results

Revenues

(in thousands of US$)	Year Ended December 31 2013	Year Ended December 31 2012	Three Months Ended December 31 2013	Three Months Ended December 31 2012
Net crude oil and gas sales	$ 4,485,046	$ 3,677,652	$ 1,171,561	$ 1,030,781
Trading revenue	141,813	207,110	30,990	15,908
Total Revenue	**$ 4,626,859**	**$ 3,884,762**	**$ 1,202,551**	**$ 1,046,689**
$ per boe oil and gas	93.95	96.58	90.66	94.61
$ per bbl trading	101.40	114.62	99.11	100.66
$ Total average revenue per boe	**94.16**	**97.39**	**90.86**	**94.70**

Despite the approximately 1.7 million barrels produced and used in line-fill for the Bicentenario pipeline and volumes delivered to Ecopetrol as part of the PAP settlement agreement, revenues for 2013 were $4,627 million, higher by 19% as compared to 2012 and mainly driven by higher volume sales. For additional details related to oil and gas sales, please refer to section 4 – "Operating Results - Commercial Activities".

Following is an analysis of the revenue drivers for 2013 as compared to 2012:

	Year Ended December 31 2013	2012	Difference	% Change
Total of boe sold (Mboe)	49,137	39,887	9,250	23%
Avg. Combined Price - oil & gas and trading ($/boe)	94.16	97.39	(3.23)	-3%
Total Revenue	**4,626,859**	**3,884,762**	**742,097**	**19%**

Drivers for the revenue increase:		
Due to Volume	$ 900,887	121%
Due to Price	(158,790)	-21%
	$ 742,097	

Following is an analysis of the revenue drivers for the fourth quarter of 2013 as compared to the fourth quarter of 2012:

	Three Months Ended December 31 2013	2012	Difference	% Change
Total of boe sold (Mboe)	13,235	11,053	2,182	20%
Avg. Combined Price - oil & gas and trading ($/boe)	90.86	94.70	(3.84)	-4%
Total Revenue	**1,202,551**	**1,046,689**	**155,862**	**15%**

Drivers for the revenue increase:		
Due to Volume	$ 206,685	133%
Due to Price	(50,823)	-33%
	$ 155,862	

Operating Costs

(in thousands of US$)	Year Ended December 31 2013	2012	Three Months Ended December 31 2013	2012
Oil and Gas Operating Costs	$ 1,652,021	$ 1,320,396	$ 423,976	$ 434,665
Trading Operating Costs	139,657	201,004	30,751	15,328
(Underlift) Overlift	(68,348)	65,020	(20,311)	90,079
Total Cost	**$ 1,723,330**	**$ 1,586,420**	**$ 434,416**	**$ 540,072**
$ per boe crude oil and gas	34.61	34.67	32.80	39.90
$ per bbl Trading Operating Costs	99.86	111.24	98.35	96.99
$ per boe (Under)/Overlift	(1.43)	1.71	(1.57)	8.27
$ Total average cost per boe	**35.07**	**39.77**	**32.82**	**48.86**

Total operating cost for 2013 was $1,723 million compared to $1,586 million for 2012, a combination of an increase in oil and gas produced and an increase in the volume of oil for trading. Total average cost for 2013 was $35.07/boe, lower by 12% as compared to $39.77/boe for 2012. Cost for oil and gas produced and sold in the current quarter was $32.80/boe compared to $39.90/boe for the same quarter in 2012. The decrease was mainly due to:

- Lower volumes of oil transported via tank truck during the fourth quarter of 2013.
- Decrease in combined diluent costs by $5.58/bbl as compared to the same quarter of 2012. The Company increased the volume of its own crude used in blending and consequently reduced the volume of purchased diluents.
- Included in the results of fourth quarter of 2012 was an overlift of $92 million (equivalent to $8.87/bbl) to settle the additional volume to Ecopetrol under PAP in Quifa SW field.
- Average cost for oil for trading decreased from $111.24/bbl in 2012 to $99.86/bbl in the current year as a result of the decrease in international market oil prices.

For additional details related to operating costs, please refer to section 4 – "Operating Costs and Cost Reduction Initiatives."

Depletion, Depreciation and Amortization

(in thousands of US$)	Year Ended December 31 2013	2012	Three Months Ended December 31 2013	2012
Depletion, depreciation and amortization	$ 1,379,393	$ 953,504	$ 344,606	$ 307,360
$/per boe sales	28.07	23.91	26.04	27.81

Depletion, depreciation and amortization ("**DD&A**") costs for 2013 was $1,379 million compared to $953.5 million in the same period of 2012. The increase of 45% over 2012 was primarily due to: (i) increase in production and higher capitalized costs that are subject to depreciation; (ii) higher depreciable cost base of oil and gas properties from the acquisition of PetroMagdalena, C&C, Petrominerales and interest in Block Z-1, which are depreciated at a higher rate based on reserve life; and (iii) higher depreciable cost base of the Rubiales field, which is depreciated over the remaining life of the contract expiring in 2016. DD&A per boe for the fourth quarter of 2013 was $26,04/boe, 6% lower than the $27.81/boe for the fourth quarter of 2012. As a result of the addition to proved and probable reserves during 2013, starting with the fourth quarter of 2013 the majority of the Company's assets (with the exception of the Rubiales field) are being depleted over a larger 2P reserve pool.

General and Administrative Costs

(in thousands of US$)	Year Ended December 31 2013	2012	Three Months Ended December 31 2013	2012
General and administrative costs	$ 336,572	$ 278,386	$ 112,808	$ 77,028
$/per boe sales	6.85	6.98	8.52	6.97

General and Administrative costs increased to $336.6 million in 2013 from $278.4 million in 2012, mainly due to:

- The higher number of direct and indirect employees during 2013 due to the acquisitions of Petrominerales, C&C and PetroMagdalena, and a significant increase in the exploratory and producing activities of the Company. Total employees as at December 31, 2013 were 2,816 compared to 2,273 in 2012, a 24% increase.
- The remaining increase was mainly due to additional costs related to expansions in Colombia, Brazil, Peru and Papua New Guinea, and in the cost of back office, office rental, field personnel and technical assistance to support

the growth of production and exploration activities.

Finance Costs

(in thousands of US$)	Year Ended December 31 2013	Year Ended December 31 2012	Three Months Ended December 31 2013	Three Months Ended December 31 2012
Finance costs	$ 162,402	$ 92,860	$ 43,298	$ 24,881

Finance costs include interest on the Company's bank loans, convertible debentures, senior notes, revolving credit facilities, working capital loans, finance leases and fees on letters of credit. For 2013, interest expenses totaled $162.4 million compared to $92.9 million for 2012. The increase in finance costs is primarily due to the $1 billion Senior Notes that were issued in March 2013 and the finance cost of the committed facility related to the Petrominerales acquisition.

Foreign Exchange

(in thousands of US$)	Year Ended December 31 2013	Year Ended December 31 2012	Three Months Ended December 31 2013	Three Months Ended December 31 2012
Foreign exchange gain (loss)	$ 6,325	$ 577	$ (4,655)	$ 13,421

The U.S. dollar is the Company's functional currency. Foreign exchange gains or losses primarily result from the movement of the Colombian peso ("**COP**") against the U.S. dollar. A significant portion of the Company's operating and capital expenditures, as well as assets and liabilities, are denominated in COP. During 2013, the COP depreciated against the U.S. dollar by 8.97% as compared to an appreciation by the same percentage during 2012. Foreign exchange gain for 2013 was $6 million compared to an income of $0.6 million for the same period of 2012. The foreign exchange gain for 2013 was mainly due to unrealized gain from the translation of COP-denominated balances into the U.S. dollar.

Income Tax Expense

(in thousands of US$)	Year Ended December 31 2013	Year Ended December 31 2012	Three Months Ended December 31 2013	Three Months Ended December 31 2012
Current income tax	$ 461,548	$ 469,217	$ 89,434	$ 122,916
Deferred income tax	43,428	(179,379)	29,795	(85,119)
Total Income Tax Expense	**$ 504,976**	**$ 289,838**	**$ 119,229**	**$ 37,797**

The Canadian statutory combined income tax rate was 26.50% for 2012 and 2013. The Peruvian income tax rate for Block Z-1 was 22% for both 2012 and 2013.

The Colombian statutory tax rate for 2012 was 33%. The Colombian Congress approved a new tax law in December 2012, which came into effect on January 1, 2013, whereby the general income tax rate was reduced from 33% to 25%. In addition, the law introduced a fairness tax ("**CREE**") at the rate of 9% to substitute for the elimination of certain payroll taxes primarily related to low-income salaries, which effectively increased the income tax rate to 34%.

The effective tax rate (income tax expenses as a percentage of net earnings before income tax) was 55% for 2013 compared to 35% for 2012. The Company's effective tax rate differs from the statutory rate due to the following:

- Expenses that are not deductible for tax purposes (such as share-based compensation, foreign exchange gains or losses, and other non-deductible expenditures in both Canada and Colombia);
- Corporate expenses that result in tax loss carry forwards, except for which no deferred tax assets and recovery have been recognized. When the Company has a reasonable expectation to utilize those losses in the future, a deferred tax asset and a corresponding deferred tax recovery may be recognized which would reduce the income tax expense; and
- Foreign exchange effect on the deferred tax, which is determined on COP-denominated assets and liabilities. The Company's assets are primarily located in Colombia. As a result, the tax base of these assets is denominated in COP, and the related deferred tax balances are subject to fluctuations in the U.S.-COP exchange rate. The appreciation of the COP against the U.S. dollar by 8.97% during the year resulted in an estimated unrealized deferred income tax expense of $98.7 million. In comparison, the Company recorded a $90.4 million unrealized income tax recovery during 2012 as a result of the depreciation of the COP against the U.S. dollar by 8.98%.

Financial Position

Debts and Credit Instruments

The Company was compliant with all of its debt covenants during the fourth quarter of 2013. The following debts were outstanding as at December 31, 2013.

2011 Senior Notes

The 2011 Senior Notes, due December 12, 2021, are direct and unsecured with an interest rate of 7.25% payable semi-annually (the "**2011 Senior Notes**"). The 2011 Senior Notes are listed on the Official List of the Luxembourg Stock Exchange and trade on the Euro MTF. On November 28, 2013, the Company closed a reopening of the 2011 Senior Notes for $300 million. As at December 31, 2013, the aggregate principal amount of 2011 Senior Notes outstanding was $1,012 million.

2013 Senior Notes due 2023

The 2013 Senior Notes, due March 28, 2023, are direct and unsecured with an interest rate of 5.125% payable semi-annually. The 2013 Senior Notes are listed on the Official List of the Luxembourg Stock Exchange. As at December 31, 2013, the aggregate principal amount of the 2013 Senior Notes outstanding was $1 billion.

2013 Senior Notes due 2019

The 2013 Senior Notes, due July 26, 2019, are direct and unsecured with an interest rate of 5.375% payable semi-annually. The 2013 Senior Notes are listed on the Official List of the Luxembourg Stock Exchange. As at December 31, 2013, the aggregate principal amount of the 2013 Senior Notes outstanding was $1.3 billion.

Revolving Credit Facilities

On September 13, 2012, the Company entered into two Revolving Credit and Guaranty Agreements: (i) a $400 million Revolving Credit and Guaranty Agreement (the "**U.S. Dollar Facility**") with a syndicate of international lenders and Bank of America, N.A. as the administrative agent; and (ii) Meta Petroleum Corp. Colombia Branch and Pacific Stratus Energy Corp. Colombia Branch entered into a Colombian peso equivalent of a $282 million Revolving Credit Agreement as borrowers (the "**Colombian Peso Facility**") with a syndicate of Colombian lenders and Sociedad Fiduciaria Bogotá, S.A. as the administrative agent.

The revolving credit facilities have an interest rate determined in accordance with the ratings assigned to the Company's senior debt securities by Standard & Poor's Ratings Group, Moody's and Fitch Inc. Based on the Company's credit rating as of December 2013, the interest rate was LIBOR + 2.75% under the U.S. Dollar facility and DTF+2.25% under the Colombian Peso Facility. In addition, the Company is required to pay commitment fees of 0.95% on the unutilized portion under the U.S. Dollar Facility and 0.40% under the Colombian Peso Facility.

As at December 31, 2013, the Company had drawn down the $400 million U.S. Dollar Facility. The $282 million equivalent remained available under the Colombian Peso Facility. There was no drawdown of the Peso facility during the year. Both the U.S. Dollar Facility and the Colombian Peso Facility remain fully committed to their maturity in 2015.

Petrominerales Acquisition

This acquisition was financed with a combination of the Revolving Credit U.S. Dollar Facility and the reopening of the 2011 Senior Notes and 2013 Senior Notes.

Bank of America Credit Facility

On May 2, 2013, the Company entered into a $109 million Credit and Guaranty Agreement with Bank of America, N.A. as lender. Proceeds from this facility were used in part to repay the entire $100 million outstanding on the Itau Credit Facility. This loan has a maturity of 44 months from the date of the loan and an interest rate of LIBOR + 1.5%.

Convertible Debentures

The Company has repaid the convertible unsecured subordinated debentures due August 29, 2013 (the "**Debentures**") of C$2.7 million in face amount. The Debentures bore interest at 8% annually and were payable semi-annually.

Working Capital Loans

From time to time, we maintain working capital facilities with several banks. As of December 31, 2013, our current facilities are with Citibank, N.A., Bank of America, N.A., JPMorgan Chase Bank, N.A. and Mercantil Commerce Bank, N.A. The terms of these loans are generally less than a year. As at December 31, 2013, we had $270 million in borrowings outstanding under these Working Capital Facilities and the interest rates have a range between LIBOR + 0.95% and LIBOR + 1.25%.

Letters of Credit

As at December 31, 2013, the Company had issued letters of credit and guarantees for exploration and operational commitments for a total of $480.3 million.

Outstanding Share Data

Common Shares

As at December 31, 2013, 322,503,752 common shares were issued and outstanding.

The Company does not have shares subject to escrow restrictions or pooling agreements.

Stock Options and Warrants

As at December 31, 2013 there were no warrants outstanding. 25,917,692 stock options were outstanding, of which all were exercisable.

Liquidity and Capital Resources

Liquidity

Funds flow provided by operating activities for 2013 totaled $1,913 million ($1,387 million for 2012). The increase in funds flow in 2013 was the result of an increase in production and higher combined crude oil and gas netback. The Company has been generating cash flows from operations from the sale of crude oil and natural gas and continues to plan for increased future production.

As at December 31, 2013, the Company had negative working capital of $495.1 million, mainly comprised of $633 million of cash and cash equivalents, $1,038 million of account receivables, $59.5 million of inventory, $132.2 million of income tax receivable, $2.8 million of prepaid expenses, $1,683 million of accounts payable and accrued liabilities, $106 million of income tax payable, $553.6 million of the current portion of long-term debt and $18 million of finance lease obligations.

As at December 31, 2013, the Company had drawn down its $400 million U.S. Dollar Facility, and has $282 million available in its Colombian Peso Facility. The Company drew down the $400 million outstanding on the U.S. Dollar Facility on December 3, 2013, and prepaid $122 million on the Colombian Peso Facility on November 27, 2013; both facilities remain fully committed until 2015.

During February 2013, the Company entered into and subsequently drew down on a new credit facility with Banco Itau for $100 million. The $100 million outstanding on the Itau facility has since been fully repaid with a new $109 million short-term credit facility from Bank of America.

The Company believes it has adequate resources to fund its capital plan for 2014 with its cash flows from operations and current debt facilities. With respect to the Company's broader integration strategy, the Company will pay for the expansion plan with its own cash flow. However, if additional resources are required, there are possible sources of funds available to the Company to finance additional capital expenditures and operations including the revolving credit facility, existing working capital incurring new debt, and the issuance of additional common shares if necessary.

As of December 2013, the Company has entered into working capital facilities with several banks, which includes Bank of America, N.A., Citibank, N.A., Itau BBA and Mercantil Commerce Bank, N.A. as lenders. Proceeds from these facilities will be used for working capital. These loans have a maximum maturity of 3 months from the date of the loans with an interest rate that will be negotiated when the Company needs the funds. As at December 31, 2013, the Company has drawn down $270 million with an interest rate range of LIBOR + 0.95% to LIBOR + 1.25%.

10. Commitments and Contingencies

Tax Review in Colombia

The Company currently has a number of tax filings under review by the Colombian tax authority ("**DIAN**").

The DIAN has reassessed value-added tax ("**IVA**") for 2009 on the basis that the volume of oil produced and used for internal consumption at certain fields in Colombia should have been subjected to IVA. The amount reassessed, including interest and penalties, is estimated to be $10 million. The Company disagrees with the DIAN's reassessment and as of September 30, 2013 an official appeal has been initiated. Several other taxation periods through to 2011 in respect of IVA on field oil consumption are currently under review by the DIAN. For the periods that are under review, if the DIAN's views were to prevail, the Company estimates that the IVA, including interest and penalties, could range between $12 million and $41 million. The Company continues to utilize oil produced for internal consumption, which is an accepted practice for the oil industry in Colombia.

The DIAN is also reviewing certain income tax deductions in respect to the special tax benefit for qualifying petroleum assets, as well as other exploration expenditures. To date, the DIAN has reassessed $12 million of tax owing, including estimated interest and penalties, with respect to the denied deductions.

As of December 31, 2013, the Company believes that the disagreements with the DIAN related to IVA and denied income tax deductions will be resolved in favour of the Company. As a result, no provision has been made in the financial statements.

High Price Royalty in Colombia

The Company has certain exploration contracts acquired through business acquisitions where there existed outstanding disagreements with the Agencia Nacional de Hidrocarburos (National Hydrocarbon Agency or "**ANH**" of Colombia) relating to the interpretation of the high-price participation clause. These contracts require high-price participation payments to be paid to the ANH once an exploitation area within a contracted area has cumulatively produced five million or more barrels of oil. The disagreement is around whether the exploitation areas under these contracts should be determined individually or combined with other exploitation areas within the same contracted area, for the purpose of determining the five million barrel threshold. The ANH has interpreted that the high-price participation should be calculated on a combined basis.

The Company disagrees with the ANH's interpretation, and asserts in accordance with the exploration contracts, the five million barrel threshold should be applied on each of the exploitation areas within a contracted area. The Company has several contracts that are subject to the ANH high-price participation. One of these contracts is the Corcel Block, which was acquired as part of the Petrominerales acquisition and the only one for which an arbitration process has been initiated. However, the arbitration process for Corcel was under suspension at the time the Company acquired Petrominerales. The amount under arbitration was approximately $178 million plus related interest of $70 million as of December 31, 2013. The Company also disagrees with the interest rate that the ANH has used in calculating the interest cost. The Company asserts that since the high-price participation is denominated in the U.S. dollar, the contract requires the interest rate to be three-month LIBOR + 4%, whereas the ANH has applied the highest legally authorized interest rate on Colombian Peso liabilities, which was over 20%. An amount under discussion with the ANH for another contract is approximately $64 million plus interest.

The Company and the ANH are currently in discussion to further understand the differences in interpreting these exploration contracts, and expect to resolve these differences within one year. The Company believes that it has a strong position with respect to the high-price participation based on legal interpretation of the contracts and technical data available. However, in accordance with IFRS 3 to account for business acquisitions, the Company is required to and has recorded a liability for such contingencies as of the date of acquisition, even though the Company believes the disagreement will be resolved in favour of the Company. The Company does not disclose the amount recognized as required by paragraphs 84 and 85 of IAS 37, on the grounds that this would be prejudicial to the outcome of the resolution.

Commitments

As part of the Company's normal course of business, the Company has entered into arrangements that will impact the Company's future operations and liquidity. The principal commitments of the Company are ship-or-pay arrangements on crude oil and gas transportation, asset retirement obligations, debt repayments, and service contracts with suppliers in relation to the exploration and operation of oil properties and engineering and construction contracts, among others.

Disclosure concerning the Company's significant commitments can be found in Note 22 of the Consolidated Financial Statements. The Company has no off-balance sheet arrangements.

11. Risk Management Contracts

The Company has entered into derivative financial instruments to reduce the exposure to unfavourable movements in commodity prices, interest rates and foreign exchange rates. The Company has established a system of internal controls to minimize risks associated with its derivative program and does not intend to use derivative financial instruments for speculative purposes.

Disclosure concerning the Company's Risk Management Contracts can be found in Note 25 of the Consolidated Financial Statements.

12. Selected Quarterly Information

(in thousands of US$)	2013 Q4	2013 Q3	2013 Q2	2013 Q1	2012 Q4	2012 Q3	2012 Q2	2012 Q1
Financials:								
Net sales	$ 1,202,551	$ 1,109,973	$1,055,573	$1,258,762	$1,046,689	$ 870,369	$1,035,854	$ 931,850
Net earnings (loss) attributable to equity holders of the parent for the period	142,958	91,473	65,732	130,242	(23,777)	68,817	224,344	258,345
Earnings (loss) per share								
- basic	0.44	0.28	0.20	0.41	(0.08)	0.23	0.76	0.88
- diluted	0.44	0.28	0.20	0.40	(0.08)	0.23	0.74	0.85

13. Related-Party Transactions

According to IFRS, parties are considered to be related if one party has the ability to “control” (financially or by share capital) the other party or have significant influence (management) on the other party in making financial, commercial and operational decisions. On May 31, 2012, the board of directors of the Company created the New Business Opportunities Committee (the “**NBOC**”) to review and approve related-party transactions. The NBOC is comprised of the following independent directors: Miguel Rodriguez (Chair), Dennis Mills, Victor Rivera and Hernan Martinez. The NBOC is apprised of related-party transactions prior to implementation, engages independent legal counsel as needed, and meets *in camera* to deliberate. The NBOC also reviews the business rationale for each transaction and ensures that the transaction is in compliance with applicable securities laws and the Company’s debt covenants.

The Company’s internal audit and legal compliance departments also monitor related-party transactions. The audit and legal compliance teams work together to compose a list of potential related parties. This list is crosschecked against the Company’s list of suppliers and other creditors.

The related-party transactions during the current quarter corresponded to the normal course of operations and were measured at fair value, which is the amount of consideration established and agreed to by the related parties and which, in the opinion of management and the NBOC, are considered similar to those negotiable with third parties.

The following sets out the details of the Company’s related-party transactions:

a) In June 2007, the Company entered into a 5-year lease agreement with Blue Pacific for administrative office space in one of its Bogotá, Colombia locations. Monthly rent expense of $0,087 million is payable to Blue Pacific under this agreement. Three directors and officers of the Company control, or provide investment advice to the holders of, 67.2% of the shares of Blue Pacific. During 2011, the lease was amended to include additional space in Bogota for a 10-year term with a monthly rent of $0.5 million, and assignment of the lessor to an entity controlled by Blue Pacific.

b) As at December 31, 2013, the Company had trade accounts receivable of $0.2 million (December 31, 2012:$4.4 million) from Proelectrica, in which the Company has a 24.9% indirect interest and which is 31.49% owned by Blue Pacific. The Company’s and Blue Pacific’s indirect interests are held through Pacific Power. Revenue from Proelectrica in the normal course of the Company’s business was $31.5 million for the year ending December 31, 2013 (2012:$39.3 million).

   In October 2012, the Company and Ecopetrol signed two Build, Own, Manage, and Transfer (“**BOMT**”) agreements with Consorcio Genser Power-Proelectrica and its subsidiaries (“Genser-Proelectrica”) to acquire certain power generation assets for the Rubiales field. Genser-Proelectrica is a joint venture between Proelectrica and Genser Power Inc. which is 51% owned by Pacific Power. Total commitment under the BOMT agreements is $229.7 million over ten years. In April 2013, the Company and Ecopetrol entered into another agreement with Genser-Proelectrica to acquire additional assets for a total commitment of $57 million over ten years. At the end of the Rubiales Association Contract in 2016, the Company’s obligations along with the power generation assets will be transferred to Ecopetrol. During the year ending December 31, 2013, those assets were under construction and the Company paid cash advances of $9.4 million (2012: Nil). The Company has accounts payable of $0.4 million (December 2012: Nil) due to Genser-Proelectrica.

c) During the year ending December 31, 2013, the Company paid $34 million (2012:$40.7 million) to Transportadora Del Meta S.A.S. (“Transmeta”) in crude oil transportation costs. In addition, the Company has accounts receivable of $1.5 million (2012 - $2.4 million) from Transmeta and accounts payable of $1.7 million (2012:$8.5 million) to Transmeta as at December 31, 2013. Transmeta is controlled by a director of the Company.

d) Loans receivable from related parties in the aggregate amount of $452 (December 31, 2012:$179) are due from two director and six officers (2012 – three directors and three officers) of the Company. The loans are non-interest bearing and payable in equal monthly payments over a 48-month terms.

e) The Company has entered into aircraft transportation agreements with Petroleum Aviation Services S.A.S. ("PAS"), a company controlled by a director of the Company. During 2013, the Company paid $14.3 million (2012 - $14.3 million) in fees as set out under the transportation agreements. The Company accounts payable to PAS as at December 31, 2013 $2.5 million (2012:$2.8 million).

f) During the year ending, December 31, 2013, the Company paid $122.6 million to ODL (2012:$125.8 million) for crude oil transport services under the pipeline take or pay agreement, and has accounts payable of $7.4 million to ODL as at December 31, 2013 (2012:$5 million). In addition, the Company received $1.2 million from ODL during the year ending December 31, 2013 (2012:$0.8 million) with respect to certain administrative services and rental equipment and machinery. The Company accounts receivable from ODL as at December 31, 2013 $0.1 million (2012:$0.2 million).

g) As at December 31, 2013, the balance of loans outstanding to Bicentenario under the agreement in note 17 (other assets) is $42 million (December 31, 2012: $32.6 million). Interest income of $2.2 million was recognized during the year ending December 31, 2013 (2012: $5.8 million). The Company has received $0.7 million as at December 31, 2013 (2012: $2.1 million) with respect to certain administrative services and rental equipment and machinery and has accounts receivable from Bicentenario as at December 31, 2013 $77.5 million. In addition, the Company has advanced $90 million as of December 31, 2013 (December 31, 2012: Nil) to Bicentenario as a prepayment of transport tariff, which is amortized against the barrels transported. The advance is included in accounts receivable as of December 31, 2013.

h) During 2013, the Company paid $0.6 million (2012: $2.5 million) to Helicopteros Nacionales de Colombia S.A.S. ("Helicol") with respect to air transportation services. Helicol is controlled by a director of the Company.

i) The Company has established two charitable foundations in Colombia, Pacific Rubiales Foundation and Vichituni Foundation (acquired as part of the Petrominerales acquisition), with the objective of advancing social and community development projects in the country. During 2013, the Company contributed $68.2 million to these foundations (2012: $40.7 million).

j) In October 2012 the Company entered into an agreement and consent with Pacific Coal, Blue Advanced Colloidal Fuels Corp. ("**Blue ACF**"), Alpha Ventures Finance Inc. ("**Alpha**"), and an unrelated party whereby the Company acquired from Pacific Coal a right to a 5% equity interest in Blue ACF for cash consideration of $5 million. Blue ACF is company engaged in developing colloidal fuels, and is currently 100% owned by Alpha which is controlled by Blue Pacific. As part of the purchase Pacific Coal has also assigned to the Company the right to acquire up to an additional 5% equity interest in Blue ACF for additional investment of up to $5 million. The Company currently has a 14.4% equity interest in Pacific Coal.

14. Accounting Policies, Critical Judgments, and Estimates

Significant Accounting Policies

The accounting policies adopted by the Company are consistent with those disclosed in detail in the 2013 Annual Audited Consolidated Financial Statements.

Critical Judgments in Applying Accounting Policies

The following critical judgments have been made by the Company in applying accounting policies which have the most significant impact on the amounts recognized in the consolidated financial statements.

Cash generating units

The determination of cash generating units (“**CGUs**”) requires the Company to apply judgments, and the CGUs may change over time to reflect changes in the Company’s oil and gas assets. CGUs have been identified to be the major areas within which there exist groups of producing blocks that share similar characteristics, infrastructure, and cash inflows that are largely independent of cash inflows of other groups of assets. The Company prepares and reviews separate detailed budgets and forecast calculations for each of the CGUs. Impairment assessment is generally carried out separately for each CGU based on cash flow forecasts calculated using proven and probable reserves for each CGU (value in use).

Functional currency

The determination of the Company's functional currency requires analyzing facts that are considered primary factors, and if the result is not conclusive, the secondary factors. The analysis requires the Company to apply significant judgment since primary and secondary factors may be mixed. In determining its functional currency, the Company analyzed both the primary and secondary factors, including the currency of the Company's revenues, operating costs in the countries that it operates in, and sources of debt and equity financing.

Contingencies

By their nature, contingencies will only be resolved when one or more future events occur or fail to occur. The assessment of contingencies inherently involves the exercise of significant judgment and estimates of the outcome of future events. Refer to note 22 of the Consolidated Financial Statements.

Financing for ODL

As part of the investment in ODL Finance S.A. ("ODL") (See note 16 of the Consolidated Financial Statements), the Company has signed certain “Take-or-Pay” contracts with ODL to finance the debt obligations of ODL. The payments related to this agreement are reflected as an increase in the investments in ODL according to the Company´s participating interest instead of an operating expense. The Company was required to apply judgment in determining that these payments to ODL were made as an investment on the basis that they were directly related to meeting ODL’s debt obligations and not for financing the costs of operating the pipeline.

Foreign currency hedging for acquisition

As part of the acquisition of Petrominerales Ltd. (See note 4 of the Consolidated Financial Statements) the Company entered into forward contracts to manage the risk associated with the fluctuation of the purchase price, which was denominated in the Canadian dollar, against the U.S. dollar. These forward contracts were designated as cash flow hedges and the settlement of the forwards was included in the purchase price. The Company applied judgment in concluding that the closing of the acquisition was a highly probable event as required for the designation of these hedges, based on an assessment of the probability of closing conditions such as regulatory approval, availability of financing, and shareholder approval.

Exploration and evaluation

Exploration and Evaluation ("**E&E**") assets are tested for impairment when indicators of impairment are present and when E&E assets are transferred to oil and gas properties. In assessing impairment for E&E assets, the Company is required to apply judgment in considering various factors that determine technical feasibility and commercial viability.

Estimation Uncertainty and Assumptions

Oil and gas properties

Oil and gas properties are depreciated using the unit-of-production method. In applying the unit-of-production method, oil and gas properties in general are depleted over proved and probable reserves. Prior to October 1, 2013, the Company depleted oil and gas properties over proved reserves. Subsequently, the depletion base was changed to include both proved and probable reserves for those oil and gas properties with significant probable reserves to better reflect the increased investment by the Company in those assets. The calculation of the unit-of-production rate of amortization could be impacted to the extent that actual production in the future is different from current forecasted production based on proved reserves. This would generally result from significant changes in any of the following:

- Changes in reserves;
- The effect on reserves of differences between actual commodity prices and commodity price assumptions; and/or
- Unforeseen operational issues.

Cash generation units

The recoverable amounts of CGUs and individual assets have been determined based on the higher of value-in-use calculations and fair values less costs to sell. These calculations require the use of estimates and assumptions. It is reasonably possible that the oil price assumption may change, which may then impact the estimated life of the field and require a material adjustment to the carrying value of goodwill and tangible assets. The Company monitors internal and external indicators of impairment relating to its tangible and intangible assets. Refer to Note 15 of the Consolidated Financial Statements.

Association contracts

Certain association contracts in Colombia provide for an adjustment to the partner's share when certain volume and price thresholds are reached. As a result, from time to time the Company may be required to estimate the impact of such contracts and make the appropriate accrual.

Decommissioning costs

Decommissioning costs will be incurred by the Company at the end of the operating life of certain facilities and properties. The ultimate decommissioning costs are uncertain and cost estimates can vary in response to many factors including changes to relevant legal requirements, the emergence of new restoration techniques or experience at other production sites. The expected timing and amount of expenditure can also change, for example in response to changes in reserves or changes in laws and regulations or their interpretation. As a result, there could be significant adjustments to the asset retirement obligation established, which would affect future financial results refer to Note 20 of the Consolidated Financial Statements.

Fair value measurement

The fair values of financial instruments are estimated based on market and (third-party inputs). These estimates are subject to changes in the underlying commodity prices, interest rates, foreign exchange rates, and non-performance risk.

Acquisitions that meet the definition of a business combination require the Company to recognize the assets acquired and liabilities assumed at their fair value on the date of the acquisition. The calculation of fair value of the assets and liabilities may require the use of estimates and assumptions, such as oil and gas reserves and forecasted cash flows: Refer to Note 25 of the Consolidated Financial Statements.

During 2013, the Company acquired majority interests in CGX, Petrominerales, and the participation interests in Sabanero in Colombia. These acquisitions met the definition of a business combination on the basis that the Company acquired control and that the activities and assets acquired are capable of being conducted for the purpose of generating a return. The assets acquired and liabilities assumed under a business combination are required to be recognized at their fair value on the date of the acquisition.

The main assets acquired through CGX include $19.3 million of net working capital, $53.5 million of exploration and evaluation assets, and $7.4 million in two wharfs under construction in Guyana. The fair value attributed to the E&E acquired assets was estimated based on mean and median market data from transactions of similar offshore oil and gas assets and companies, given the very early-stage nature of activities in the Guyana Suriname Basin and limited reserve data. The fair value of the wharves was approximately determined to be their cost of construction to-date. Goodwill arising from the acquisition was primarily related to operational team and relationships in Guyana and the deferred tax liability recognized on the date of acquisition.

Through Petrominerales we acquired significant crude oil producing and exploration assets, interest in oil transport pipelines, and assumed Petrominerales' outstanding debentures. The main assets and liabilities acquired included $1,622 million of producing and exploration assets, $588 million of pipeline interests, and negative $380 million of net working capital. The fair value attributed to the oil and gas assets were estimated based on reported 2P reserves or mean and median market data from comparable transactions. These fair values are preliminary as of December 31, 2013 due to the large number of blocks acquired and the complexity associated with valuing oil and gas assets. Goodwill recognized is due to a number of factors including the synergies provided by managing a portfolio of both acquired and existing fields in Colombia, access to PMG's current production of high quality light oil to act as diluent for blending with the company's growing heavy oil production and the opportunity to secure additional oil transportation capacity through PMG's infrastructure investments.

Sabanero was a producing block owned by Maurel & Prom Colombia B.V. ("M&P Colombia") of which the Company had a 49.9% interest and Maurel and Prom S.A. ("M&P S.A.") had 50.1%. On September 1, 2013, the Company entered into an agreement with M&P Colombia whereby it would effectively pay $10 million in cash for the remaining 50.1% interest in the Sabanero block. As Sabanero was previously recognized as a jointly controlled asset, at the time of acquisition of control the previous carrying amount was considered to have been disposed of at its fair value of $179 million. In addition, 100% of the block is considered to have been acquired immediately at a consideration of $189 million, consisting of the $179 million for the fair value of the previously held asset plus $10 million of cash paid. The fair value of the 49.9% interest previously held by the Company was estimated based on the 2P reserves associated with the Sabanero block. There was no material organized work force with the purchase and accordingly no goodwill to assign. A gain on bargain purchase of approximately $9.5 million arising from the transaction was recognized in other expenses. The gain on bargain purchase was due to the fact that the Company was one of a limited number of purchasers well positioned to operate Sabanero and incorporate it into existing infrastructures and other oil assets around the block.

During 2013 we also acquired a controlling stake in Pacific Infrastructure and were subsequently diluted to below 50% upon the investment in Pacific Infrastructure by IFC. At the time of acquisition of control, the fair value of the major identifiable assets acquired included $123.6 million of staging facilities under construction and $142.9 million of intangible assets related to the Puerto Bahía port concession. The fair value attributed to the staging facilities approximated their construction cost to-date as they are in the early phases of construction. The fair value assigned to the port concession was supported by the future benefit to be derived from oil storage, export loading, and related port businesses. Goodwill arising from the acquisition was primarily related to the deferred tax liability recognized on the date of acquisition. Upon the investment by IFC, the Company lost control of Pacific Infrastructure de-recognized the assets and liabilities of Pacific Infrastructure and recognized an investment in an associate at fair value. The fair value of the investment was determined based on the consideration paid by IFC in acquiring its interest in Pacific Infrastructure. A gain of approximately $47.9 million was recognized by the Company as a result of the transaction.

15. Internal Controls over Financial Reporting (“ICFR”)

In accordance with National Instrument 52-109 Certification of Disclosure in Issuers’ Annual and Interim Filings (“**NI 52-109**”) of the Canadian Securities Administrators (“**CSA**”), the Company issues quarterly a “Certification of Interim Filings”. This Certification requires certifying officers to state that they are responsible for establishing and maintaining Disclosure Controls and Procedures (“**DC&P**”) and Internal Control Over Financial Reporting (“**ICFR**”).

During 2013, 621 controls over 37 corporate processes were evaluated. From this evaluation, the Company concluded that there were no material weaknesses or significant deficiencies in the design and effectiveness of the controls evaluated.

During 2013, Internal Audit continued reviews focused on identifying, evaluating, and addressing critical and material risks for the organization. Following are some of the most significant risks identified, as well as the actions initiated by management to mitigate them.

- Regulatory compliance: Actions include the Corruption of Foreign Public Officials Act (“**CFPOA**”), an anti-money laundering training program, and the updating of all regulatory obligations the Company has in different countries.
- Price and exchange rate volatility: Actions are focused on hedging processes and strategies in order to improve the automated environment.
- Fraud: Risk assessment is related to asset misappropriation, corruption and financial fraud. The Company has launched e-learning programs for employee fraud awareness training to help maintain fraud resistance.
- Data security and privacy protection: Actions are focused on access to the network and application security in accordance with standards.
- Health, safety, and environmental risks: The Company is operating with a zero-tolerance HSE program.

16. Outlook

The Company will continue to implement its growth strategy through 2014 by expanding its resource and reserve base and developing its production and transport capacity. The outlook for 2014 includes:

- An expectation to grow net production 15% – 25% (approximately 148 to 162 Mboe/d) from 2013.
- Total capital expenditures excluding acquisitions of approximately $2,500 million for 2014, largely driven by development drilling, exploration and production facilities in Colombia and Peru. The capital program is expected to be funded by internally generated cash flow in an expected WTI oil price environment of $90-$95.
- Exploration expenditures of $700 million, including the drilling of an additional 46 exploration wells, seismic data acquisition and early facilities. In the total drilling program, approximately four exploration wells are targeting high-impact prospects, including the Company's exploration wells in Colombia.
- $900 million to drill a planned 366 gross (207.2 net) development wells (excluding workovers), a significant increase over 2013 with activity driven by development of the Cajua field, on-going infill drilling in the Quifa SW and Rubiales fields, stepped-up light oil development in the Cubiro Block in Colombia and a significant program of development drilling in Block Z-1 in Peru.
- $580 million in the development of facilities and infrastructure, with approximately 75% directed to the Company's core producing Rubiales, Quifa SW, Cajua and Sabanero heavy oil fields. The remaining 25% will be allocated for the planned development of the CPE-6 Block as well as other mostly light oil field development in Colombia.
- As a result of the global environmental licence received for the CPE-6 Block, the Company plans to drill nine gross (4.5 net) exploration wells and 16 gross (8 net) development wells and obtain production flow tests from existing wells during 2014.

17. Additional Financial Measures

This report contains the following financial terms that are not considered in IFRS: Funds Flow from Operations, Adjusted Net Earnings, Adjusted EBITDA and Net Earnings from Operations. These non-IFRS measures do not have any standardized meaning and therefore are unlikely to be compared to similar measures presented by other companies. These non-IFRS financial measures are included because management uses this information to analyze operating performance, leverage and liquidity. Therefore, these measures should not be considered in isolation or as a substitute for measures of performance prepared in accordance with IFRS.

a) Funds Flow from Operations

The following table shows the reconciliation of funds flow from operations to cash flow from operating activities for the three and twelve months ending December 31, 2013:

	Year Ended December 31		Three Months Ended December 31	
(in thousands of US$)	**2013**	**2012**	**2013**	**2012**
Cash flow from operating activities	$ 1,637,101	$ 1,802,735	$ 473,683	$ 676,938
Changes in non-cash working capital	(276,011)	415,191	(3,168)	445,406
Funds flow from operations	**$ 1,913,112**	**$ 1,387,544**	**$ 476,851**	**$ 231,532**

b) Adjusted Net Earnings

	Year Ended December 31		Three Months Ended December 31	
(in thousands of US$)	**2013**	**2012**	**2013**	**2012**
Adjusted net earning	**$ 490,218**	**$ 650,852**	**$ 152,123**	**$ 58,698**
Non-operating items				
Other expenses	(34,461)	(30,897)	916	(21,382)
(Loss) gain from foreign exchange	6,325	577	(4,655)	13,421
(Loss) gain on risk management	(2,530)	10,130	9,801	(13,663)
Loss from equity investments	(29,147)	(102,933)	(15,227)	(60,851)
Total non-operating items	**(59,813)**	**(123,123)**	**(9,165)**	**(82,475)**
Net earnings attributable to equity holders of the parent, as reported	**$ 430,405**	**$ 527,729**	**$ 142,958**	**$ (23,777)**

"Adjusted Net Earnings" is a non-IFRS financial measure that represents Net Earnings adjusted for certain items of a non-operational nature, including non-cash items. This is one of the indicators against which the Company evaluates its performance. The reconciliation chart lists the effects of certain non-operational items that are included in the Company's financial results and may not be comparable to similar measures presented by other companies.

c) Adjusted EBITDA

The Company uses the financial measure "Adjusted EBITDA" in this MD&A, whereas in the past we have used the term EBITDA. Our calculation of this measure has not changed from previous quarters, but the terminology has changed due to guidance provided by the Ontario Securities Commission. Adjusted EBITDA is an indicator that the Company uses to assess its financial returns from normal operations, adjusting for non-cash and one-time items.

A reconciliation of Net Earnings to Adjusted EBITDA follows.

(in thousands of US$)	Year Ended December 31 2013	Year Ended December 31 2012	Three Months Ended December 31 2013	Three Months Ended December 31 2012
Net earnings	**$ 430,405**	**$ 527,729**	**$ 142,958**	**$ (23,777)**
Adjustments to net earnings				
Income taxes expense	504,976	289,838	119,229	37,797
Foreign exchange (gain) loss	(6,325)	(577)	4,655	(13,421)
Finance cost	162,402	92,860	43,298	24,881
Loss (gain) on risk management contracts	2,530	(10,130)	(9,801)	13,663
Loss from equity investment	29,147	102,933	15,227	60,851
Other expenses	34,461	30,897	(916)	21,382
Share-based compensation	39,416	32,902	(1,705)	853
Loss attributable to non-controlling interest	(9,448)	-	(2,224)	-
Depletion, depreciation and amortization	1,379,393	953,504	344,606	307,360
Adjusted EBITDA	**$ 2,566,957**	**$ 2,019,956**	**$ 655,327**	**$ 429,589**

d) Net Earnings from Operations

Additional details on Net Earnings from Operation for 2013 are provided in Section 3 - Financial Summary on page 6.

18. Sustainability Policies

The Company is committed to conducting its business in a transparent and inclusive way and ensuring the business succeeds in harmony with its surroundings. Pursuant to this commitment, the Company is hardwiring "shared value" as one of the pivotal points in the development of its corporate strategy. Through this strategy, the Company is working with different projects that seek to create business opportunities that increase its profitability while addressing needs and challenges in its local areas of operation as well as host countries.

We are also a committed partner of various organizations and initiatives focused on the advancement of corporate sustainability on a global scale and at the regional and local levels. We are an active participant in the EITI (Extractive Industry Transparency Initiative) and the Carbon Disclosure Project, and are a signatory member of the Global Compact.

Among our awards, we have been named by World Finance as the “Best Oil & Gas Sustainable Company in Latin America” and were awarded a “National Award for Social Responsibility and Sustainability” by the RS and *Corporación Calidad* magazine. Additionally, we have been recognized by the Global Compact with the Social Investment Pioneer Award.

In September 2013, the Company was selected for inclusion in the DJSI North America Index. This Index, which was established in 2005, tracks North American companies that are leaders in corporate social responsibility by using rigorous indicators in the areas of corporate, economic and social performance.

Finally, our policies, purchasing processes and procedures were internationally certified by CIPS (Chartered Institute of Purchasing Supply), making us one of 104 companies in the world with this recognition. Being awarded and recognized for our social, environmental, economic, and governance achievements is of high importance to our company and adds credibility among our stakeholders.

Advances Made in our Sustainability Commitments:

During 2013, the Company made the following advances with respect to its stakeholders and the environment:

- To date, we have trained over 400 direct and indirect employees in PRE´s security department while adhering to guidelines of the Mining and Energy Committee on Human Rights and Security. Additionally, our security department has been working with the Colombian Petroleum Association and The Ministry of National Defense, Department of Critical Infrastructure Protection on the development of security standards adapted for the hydrocarbon sector. The security area also joined local security committees in departments where the Company operates (Meta, Casanare), creating dynamic security procedures regarding prevention in operations.

- Additionally, we began to export our corporate security model to all the business units of the Company, seeking to create standards for the application of security policies which are aligned with our voluntary principles and our code of conduct and corporate ethics.

- Having an overall engagement policy is important in validating our commitment to transparent relations with our stakeholders. However, we recognize that the expectations and characteristics of every stakeholder are different and in constant evolution. This is why we have set the goal of creating a protocol that dictates basic guidelines for engagement with every stakeholder. During the final quarter of 2013, we advanced the creation of protocols for the engagement with communities and ethnic groups. Through 2014, we will pursue its implementation.

- We had a successful year with our Agents of Change volunteer program, focusing on women as key actors in the development of their communities. Over 83 volunteers from different areas of the Company transferred their knowledge to 15 chief-of-household mothers living in conditions of extreme poverty in a neighborhood in Bogota. For over three months, volunteers taught these mothers basic finance and other skills necessary to run a small business. After the training with our volunteers and other institutional allies, the mothers obtained a donation from the Company to start their small business and have shown promising financial results. The Company will repeat this model in 2014, expanding the pool of beneficiaries.

- In line with our commitment to obtain the Gender Equity Seal, our Gender Committee obtained the CEO´s approval for a corporate Gender Policy as well as a five-year action plan that will help the Company close gaps and break paradigms associated with the role of women in the industry and move towards more balanced gender relations.

- Throughout 2013, we monitored and documented our greenhouse gas emissions for submission to the Carbon Disclosure Project. We are committed to documenting, controlling, and eventually reducing our carbon footprint.

- We lead the labour working table with the Global Compact Local Network to share and promote the best practices regarding the Global Compact Labour Principles.

For further details regarding the Company's sustainability policies, please see our Sustainability Report, which is available on our website. The Sustainability Report for 2013 is expected to be released April 2014.

19. Legal Notice – Forward-Looking Information and Statements

Certain statements in this MD&A constitute forward-looking statements. Often, but not always, forward-looking statements use words or phrases such as: "expects," "does not expect" or "is expected," "anticipates" or "does not anticipate," "plans" or "planned," "estimates" or "estimated," "projects" or "projected," "forecasts" or "forecasted," "believes," "intends," "likely," "possible," "probable," "scheduled," "positioned," "goal," "objective" or state that certain actions, events or results "may,", "could", "would", "might" or "will" be taken, occur or be achieved. Such forward-looking statements, including but not limited to statements with respect to anticipated levels of production, the estimated costs and timing of the Company's planned work programs and reserves determination, involve known and unknown risks, uncertainties and other factors which may cause the actual levels of production, costs and results to be materially different from estimated levels of production, costs or results expressed or implied by such forward-looking statements. The Company believes the expectations reflected in these forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements should not be unduly relied upon. Factors that could cause actual results to differ materially from those anticipated in these forward-looking statements are described under the caption "Risks and Uncertainties." Although the Company has attempted to take into account important factors that could cause actual costs or operating results to differ materially, there may be other unforeseen factors that create costs to the Company's program and results may not be as anticipated, estimated or intended.

Statements concerning oil and gas reserve estimates may also be deemed to constitute forward-looking statements to the extent that they involve estimates of the oil and gas that will be encountered if the property is developed. The estimated values disclosed in this MD&A do not represent fair market value. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties due to the effects of aggregation.

20. Risks and Uncertainties

The business operations and earnings of the Company could be impacted by the occurrence of risks of all kinds including financial, operational, technological and political that might affect this industry. Our Enterprise Risk Management program identifies, assesses and provides action plans and controls to mitigate the occurrence of the risks described below, which can potentially affect businesses and hence the profitability and value of the shares of the Company.

The business and operation of the Company will be subject to a number of risks. The Company considers the risks set out below to be the most significant to potential investors in the Company, but does not include all of the risks associated with an investment in securities of the Company:

- Fluctuating oil and gas prices;
- Global financial conditions;
- Exploration and development;
- Operating hazards and risks;
- Security risks;
- Reserves estimates;
- Transportation costs;
- Cash flows and additional funding requirements;
- Disruptions in production;
- Political risks;
- Environmental factors;
- Title matters;
- Payment of dividends;
- Dependence on management;
- Ability to attract and retain qualified personnel;
- Changes in legislation;
- Litigation;
- Repatriation of earnings;
- Enforcement of civil liabilities;
- Competition;
- Environmental licences & required permits;
- Partner relationships;
- Oil & gas transportation;
- Availability of diluents;
- Water disposal;
- Labour relations;
- HSE works;
- Community relations;
- Fraud;
- Foreign exchange rate fluctuation;
- Business continuity;
- Regulatory compliance; and
- Shareholder relations.

If any of these risks materialize into actual events or circumstances or other possible additional risks and uncertainties of which the Company is currently unaware or which it considers not to be material in relation to the Company's business actually occur, the Company's assets, liabilities, financial condition, results of operations (including future results of operations), business and business prospects are likely to be materially and adversely affected. In such circumstances, the price of the Company's securities could decline and investors may lose all or part of their investment. For more information, please see the Company's Annual Information Form, which is available at www.sedar.com.

21. Advisories

Finding Costs

The aggregate of the finding costs incurred in the most recent financial year and the change during that year in estimated future finding costs will generally not reflect total finding costs related to reserves additions for that year.

Boe Conversion

The term "boe" is used in this MD&A. Boe may be misleading, particularly if used in isolation. A boe conversion ratio of cubic feet to barrels is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In this MD&A, we have expressed boe using the Colombian conversion standard of 5.7 Mcf: 1 bbl required by the Colombian Ministry of Mines and Energy.

All of the Company's natural gas reserves are contained in the La Creciente, Guama and other blocks in Colombia as well as in the Piedra Redonda field in Block Z-1, Peru. For all natural gas reserves in Colombia, boe's have been expressed using the Colombian conversion standard of 5.7 Mcf: 1 bbl required by the Colombian Ministry of Mines and Energy. For all natural gas reserves in Peru, boe's have been expressed using the Canadian conversion standard of 6.0 Mcf: 1 bbl. If a conversion standard of 6.0 Mcf: 1 bbl was used for all of the Company's natural gas reserves, this would result in a reduction in the Company's net 1P and 2P reserves of approximately 4.2 and 4.7 MMboe respectively.

Prospective Resources

Readers should give attention to the estimates of individual classes of resources and appreciate the differing probabilities of recovery associated with each class. Estimates of remaining (un-risked) recoverable resources include prospective resources that have not been adjusted for risk based on the chance of discovery or the chance of development and contingent resources that have not been adjusted for risk based on the chance of development. It is not an estimate of volumes that may be recovered. Actual recovery is likely to be less and may be substantially less or zero.

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates, assuming their discovery and development, and may be sub-classified based on project maturity. There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that any discovery will be technically or economically viable in order to produce any portion of the resources.

Translations

This MD&A was prepared originally in the English language and subsequently translated into Spanish and Portuguese. In the case of any differences between the English version and its translated versions, the English document shall prevail and be treated as the governing version.

22. Abbreviations

The following abbreviations are frequently used in our MD&A.

1P	Proved reserves (also known as P90)
2P	Proved reserves + Probable reserves.
3P	Proved reserves + Probable reserves + Possible reserves
bbl	Barrels
bbl/d	Barrels per day
Bcf	Billion cubic feet
boe	Barrels of oil equivalent
boe/d	Barrels of oil equivalent per day
Btu	British thermal units
Bwpd	Barrels of water per day
CBM	Cubic Billion Meter
ESP	Electro-Submersible Pump
GDP	Gross Domestic Product
ha	Hectare
km	Kilometres
KWh	Kilowatt Hour
Mbbl	Thousand barrels
Mboe	Thousand barrels of oil equivalent
MMcf/d	Million cubic feet per day
MD	Measured depth
MMbbl	Million barrels
Mmboe	Million barrels of oil equivalent
MMBtu	Million British thermal units
MMcf	Million cubic feet
MMcf/d	Million cubic feet per day
Mmscf/d	Million standard cubic feet per day
Mw	Megawatts
NGL	Natural gas liquids
OOIP	Original oil in place
Tcf	Trillion cubic feet
TD	Total depth
TVDSS	True vertical depth below sea level
USGC	US Gulf Coast
WTI	West Texas Intermediate index