PACIFIC RUBIALES ENERGY CORP.

MANAGEMENT DISCUSSION AND ANALYSIS
November 6, 2014
For the three and nine months ending September 30, 2014

Message to Shareholders

Pacific Rubiales' focus on growth and operational efficiencies continued to deliver results this quarter, including record oil and gas sales and funds flow from operations. As with other E&P companies, the drop in world oil prices materially affected our realized prices during the quarter, but our focus on operational cost efficiency has allowed us to achieve consistent financial results in this commodity price environment. While production volumes were impacted by reduced output at the Rubiales Field, we have made several important exploration discoveries that are contributing to our growth in light and medium oil production, as previously announced.

Despite the weak commodity price environment, and the challenging operating conditions during the quarter, we delivered strong results including record sales volumes and cash flow (funds flow) from operations. The Company has generated, year to date, over $2.1 billion in adjusted EBITDA and a record revenue of $4.0 billion, with a revenue of $1.3 billion and adjusted EBITDA of $635 million in the quarter. Funds flow from operations were a record of $606 million for the quarter and $1.6 billion for the year to date, with the effect of the lower commodity prices having been more than offset by a decrease in current income taxes. We continue to manage our exposure to oil price fluctuations through an established hedging program and are evaluating the optimal coverage for 2015 production. Approximately 32% of our 2014 net oil production has been hedged using zero-cost collars with an average floor price of just under $81 per barrel.

Net production of 145 Mboe/d and sales volume of 164 Mboe/d for the quarter represented 13% and 32% growth, respectively, compared to the same period last year. For the first nine months of 2014, production averaged 148 Mboe/d, in-line with the low end of the Company's annual production guidance. This guidance was predicated on expected growth in the second half of the year.

With the Rubiales Field performing below plan, impacted by limited water handling capacity and weather related impacts on operations, we now expect annual production to be at the lower end of our guidance. Production at the Rubiales Field continues to be affected by water disposal capacity, pending the final approval required to commence operation of Phase I of the Agrocascada reverse osmosis facility, which will add 0.5 million bbl/d of incremental water disposal capacity. On the other hand, the growth in light and medium oil production demonstrates the success of our diversification strategy, with the Rubiales Field now representing only 40% of our total production. Over the past 12 months, we have more than doubled our net light oil production. Approximately 10,000 bbl/d of new net light oil production has been delivered through successful exploration wells drilled in the first nine months of 2014.

During the quarter, we continued with the appraisal campaigns in the CPE-6 and Rio Ariari Blocks. Year to date, a total of 16 appraisal wells have been drilled in those two blocks, while the facilities are under construction. At CPE-6, Phase I of the central processing facility construction is completed. Commissioning and flow line construction and tie-in is expected to be finished by early December.

The company is nearing the completion of an agreement with the International Finance Corporation ("**IFC**") to sell 43% of our interest in our pipeline and transmission assets ("**Pacific Midstream**") for a total consideration of $320 million. The majority of the sale proceeds from these interests, expected next month, will be available for debt reduction and/or investment into E&P activity. The participation by the IFC underlines the strategic importance and value of our infrastructure assets, and will provide funds at an enhanced valuation. At the same time, by continuing to hold a majority interest in Pacific Midstream, we will be able to maintain the cost advantages that we currently enjoy with respect to crude oil transportation in Colombia.

Our financial and capital strategy remains focused on maintaining a healthy balance sheet and ensuring funding for our future growth, and generating strong returns to our shareholders. In light of the current weaker commodity price environment, we are evaluating all of our capital programs. Our diversified portfolio of assets has the flexibility and discretionary components to allow us to scale back capital spending while maintaining production growth. We have commodity hedges in place which provide cash flow security in the short and medium term. We have recently improved our balance sheet by replacing all our short-term debt with long-term bonds, at more favorable terms and lower interest rates. In addition we have opportunities for cost savings and assets dispositions to provide additional funds, if needed. Our previous guidance for 2014 E&P expenditures was $2.5 billion – we now expect that this number will be closer to $2.3 billion, as we compensate for annual production at the low end of our guidance and lower world oil prices in the second half of 2014. The Company will allocate capital spending on the highest return, most material projects in our portfolio. Looking into the future, we will continue to pursue growth and diversification opportunities, while maintaining capital discipline and focusing on superior shareholder returns. In October of this year we became one of the first independent oil and gas producers to sign an agreement with Pemex, the Mexican national oil company, following the comprehensive energy reform passed in Mexico. We expect Mexico to be a significant driver of future growth for the Company and are committed to further advancing our plans in the country as we continue to build the leading Independent Latin American focused E&P Company.

Ronald Pantin
Chief Executive Officer
November 6, 2014

Content

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.

For more information please see the Company´s Annual Information Form, which is available at www.sedar.com.

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 Interim Condensed Consolidated Financial Statements and related notes for the third quarter of 2014 and 2013. 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 quarters ending September 30, 2014 and September 30, 2013, 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 16.

Additional information with respect to the Company has been filed with Canadian securities regulatory authorities, including the Company's quarterly and annual financial statements and the Annual Information Form, which 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. Highlights for the Third Quarter of 2014

(in thousands of US$ except per share amounts or as noted)	Q3 2014	Q3 2013 [1]	Q2 2014	Nine Months Ending September 30 2014	Nine Months Ending September 30 2013 [1]
Financials					
Oil and gas sales ($)	**$ 1,330,395**	$ 1,109,973	$ 1,344,666	**$ 3,958,514**	$ 3,424,308
Adjusted EBITDA [2]	**635,079**	612,133	721,572	**2,064,809**	1,911,630
Adjusted EBITDA margin (Adjusted EBITDA/Revenues)	**48%**	55%	54%	**52%**	56%
Per share - basic ($) [3]	**2.02**	1.89	2.30	**6.55**	6.85
Funds flow from operations [2]	**606,214**	455,100	531,649	**1,611,472**	1,436,261
Funds flow from operations margin (Funds flow from operations/Revenues)	**46%**	41%	40%	**41%**	42%
Per share - basic ($) [3]	**1.93**	1.41	1.70	**5.11**	4.45
Net earnings from operations [2]	**200,619**	237,171	337,505	**868,913**	835,722
Per share - basic ($) [3]	**0.64**	0.73	1.08	**2.76**	2.59
Net earnings [4]	**3,484**	84,013	228,527	**351,251**	285,670
Per share - basic ($) [3]	**0.01**	0.26	0.73	**1.11**	0.89
Cash dividends	**52,075**	53,394	51,858	**155,866**	142,215
Cash dividends per share	**0.17**	0.17	0.17	**0.49**	0.44
Sales and Production					
Average sales volumes (boe/d)	**163,617**	123,689	155,027	**156,873**	131,506
Average oil and gas sales (boe/d)	148,790	119,465	146,408	145,514	127,528
Average trading sales (bbl/d)	14,827	4,224	8,619	11,360	3,978
Average net production (boe/d)	**144,722**	127,728	149,118	**147,541**	127,723
Average net production oil (bbl/d)	134,453	117,219	138,756	137,096	116,869
Average net production gas (boe/d)	10,269	10,509	10,362	10,445	10,854
Combined price ($/boe)	**88.05**	97.29	94.95	**92.07**	95.17
Combined netback ($/boe)	**55.08**	62.52	62.76	**60.44**	61.28
Operating Activities					
Capital expenditures	**645,312**	422,425	510,233	**1,624,454**	1,251,408
Capital expenditures for new acquisitions	**276,779**	36,092	-	**289,279**	301,765
Successful exploration, appraisal and stratigraphic drilled wells (gross)	**11**	3	8	**28**	11

1. Net Earnings for 2013 have been restated upon the first-time adoption of IFRS 9 – Financial Instruments and the finalization of the purchase price allocation of the C&C Energia Ltd. acquisition. Refer to Note 28 and Note 3 of the third-quarter 2014 Interim Condensed Consolidated Financial Statements.
2. See "Additional Financial Measures" on page 28.
3. The basic weighted average number of common shares outstanding for the third quarters of 2014 and 2013 were 314,707,053 and 323,404,942 respectively. The basic weighted average number of common shares outstanding for the second quarter of 2014 was 313,581,537.
4. Net earnings attributable to equity holders of the parent.

Third Quarter 2014 Highlights

Financial

- Revenue from oil and gas sales increased to $1.33 billion this quarter despite the challenge presented by the decline in crude oil market prices through the quarter. Oil and gas sales were 148,790 boe/d, higher than the 146,408 boe/d of last quarter, notwithstanding a modest drop in own production over the previous quarter. Our sales from crude oil trading increased from 8,619 bbl/d last quarter to 14,827 bbl/d this quarter, again demonstrating the strength of our commercial activities. Year-to-date revenue from oil and gas sales was $3.96 billion, a 16% increase from $3.42 billion in 2013.

- Combined operating netback from oil and gas production for the quarter was $55.08/boe, lower than the $62.76/boe from the last quarter and the $62.52/boe for the same quarter in 2013. The decrease is attributable to the significant decline in the market prices for crude oil, as combined operating costs have remained stable. Combined operating netback for the first nine months of 2014 remained strong at $60.44/boe, slightly lower than the $61.28/boe for the same period in 2013 despite a combined price decrease of $3.10/boe from $95.17/boe in the prior year to $92.07/boe in the current period.
- Despite the impact from lower oil prices, we continued to deliver healthy returns with Adjusted EBITDA at $635 million and Funds Flow of $606 million. The decrease in Adjusted EBITDA compared to the last quarter was primarily due to lower realized prices. For the year to date, Adjusted EBITDA increased by 8% to $2.07 billion from $1.91 billion for the same nine-months period of 2013, and Funds Flow increased by 12% to $1.61 bilion from $1.44 billion for the same comparative periods.
- Net earnings totaled $3.5 million for the quarter, significantly impacted by the foreign exchange fluctuation due to the 8% depreciation of the Colombian peso against the U.S. dollar. The negative impact on Net Earnings was largely unrealized, arising mostly on the translation of the tax base of long-lived oil and gas assets in Colombia. Net Earnings after adjusting for the unrealized currency translation effect would have been $127.8 million for the current quarter and $412.5 million for the year to date, as shown in the table below:

	Three Months Ending September 30		Nine Months Ending September 30	
(in thousands of US$)	2014	2013	2014	2013
Earnings from operations [1]	**$ 200,619**	**$ 237,171**	**$ 868,913**	**$ 835,722**
Non-operating items and income tax expense	(197,135)	(153,158)	(517,662)	(550,052)
Net earnings for the period	**3,484**	**84,013**	**351,251**	**285,670**
Currency translation impacts				
Loss (gain) from unrealized foreign exchange	30,507	(2,743)	(8,707)	43,882
Loss (gain) from deferred income tax unrealized foreign exchange	93,786	(1,423)	69,965	98,667
Total unrealized currency translation impacts	**124,293**	**(4,166)**	**61,258**	**142,549**
Net earnings after adjusting the unrealized currency translation effect	**127,777**	**79,847**	**412,509**	**428,219**

1. See "Additional Financial Measures" on page 28.

Operational

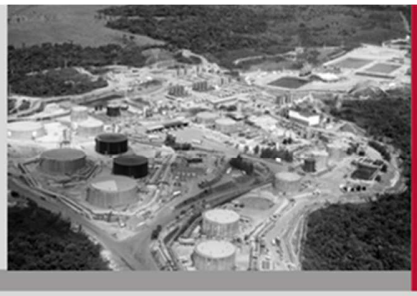
- Net production for the quarter averaged 144,722 boe/d, 13% higher than the same quarter of 2013 and 3% lower than the second quarter of 2014. Production from Rubiales decreased by 5,131 bbl/d compared to the second quarter of 2014, primarily due to restricted water disposal capacity and weather conditions impacting operations.
- On the other hand, production increased in a number of the Company's light and medium oil fields. Net production for the year to date averaged 147,541 boe/d, 15% higher than the same nine months in 2013.

Discoveries

- Continued success in the Canaguaro Block in the Llanos Basin saw a new appraisal well at Tapiti-1X come onstream. The well is currently producing approximately 1,346 bbl/d of medium gravity oil.
- In Peru, the Los Angeles well commenced long-term production testing in September and is now producing on natural flow at 2,258 bbl/d. Further exploration in offshore Block Z-1 has resulted in the discovery of new producing horizons under the existing fields and will be evaluated in the coming months.

Balance Sheet Management

- We improved our overall liquidity by repaying the majority of our short-term debt obligations using the proceeds from the issuance of $750 million 5.625% senior notes due 2025. We also initiated during the quarter an exchange offer of our 7.25% senior notes due 2021 for 5.625% senior notes due 2025, closing in October 2014 with $321.6 million of aggregate principal amount of 7.25% senior notes being exchanged, effectively reducing our interest payments and extending the maturity.



2. Cash Flow and Netbacks

(in thousands of US$ except as noted)	Q3 2014	Q3 2013	Q2 2014	Nine Months Ending September 30 2014	Nine Months Ending September 30 2013
Funds flow from operations	**606,214**	455,100	531,649	**1,611,472**	1,436,261
Revenue					
Oil and gas	1,205,227	1,069,245	1,265,033	3,657,429	3,313,485
Trading	125,168	40,728	79,633	301,085	110,823
Total revenue	**1,330,395**	1,109,973	1,344,666	**3,958,514**	3,424,308
Total volumes sold in the period (boe)	**15,052,764**	11,379,410	14,107,457	**42,826,451**	35,901,100
Price					
Oil and gas $/boe	88.05	97.29	94.95	92.07	95.17
Trading $/bbl	91.76	104.80	101.53	97.09	102.06
Total Realized price $/boe	**88.38**	97.54	95.32	**92.43**	95.38

During the quarter, Funds Flow from Operations amounted to $606 million, an increase of 33% from $455 million in the third quarter of 2013 and 14% from $532 million in the second quarter of 2014. This increase in Funds Flow from Operations resulted from a higher volume sold, a decrease in current income tax expense, dividends of $38 million received from the ODL Pipeline during the quarter and a positive impact of realized foreign exchange effect as the largest portion of our operating expenditures are incurred in Colombian pesos.

In order to limit our exposure to a lower oil price environment, the Company currently has in place a hedging program with a target coverage of around 30% of our net oil production. Our existing hedges are composed mainly of zero cost collar instruments with an average put level of $80.61/bbl, and call level of $109.48/bbl, with 32% of our estimated oil production for the fourth quarter of 2014 hedged. We are currently evaluating the optimal level of hedging for our 2015 production

Operating Netback – Oil and Gas Produced and Sold

Combined operating netback for the quarter is summarized below:

	Three Months Ending						
	September 30, 2014			June 30, 2014			September 30, 2013
	Crude Oil	Natural Gas	Combined	Crude Oil	Natural Gas	Combined	Combined
Average daily volume sold (boe/day)[1]	**138,667**	**10,123**	**148,790**	**136,108**	**10,300**	**146,408**	**119,465**
Operating netback ($/boe)							
Crude oil and natural gas sales price	92.14	31.95	**88.05**	99.76	31.33	**94.95**	**97.29**
Production cost of barrels sold [2]	16.34	3.65	**15.48**	16.71	3.17	**15.75**	**16.35**
Transportation (trucking and pipeline) [3]	14.13	(0.08)	**13.16**	14.99	0.02	**13.93**	**14.41**
Diluent cost	2.30	-	**2.15**	2.19	-	**2.03**	**3.50**
Total operating cost	**32.77**	**3.57**	**30.79**	**33.89**	**3.19**	**31.71**	**34.26**
Overlift/Underlift [4]	(0.01)	(0.65)	**(0.06)**	(1.01)	(0.15)	**(0.95)**	**(1.25)**
Other costs [5]	2.27	1.91	**2.24**	1.34	2.55	**1.43**	**1.76**
Total operating cost including overlift/underlift and other costs	**35.03**	**4.83**	**32.97**	**34.22**	**5.59**	**32.19**	**34.77**
Operating netback crude oil and gas ($/boe)	**57.11**	**27.12**	**55.08**	**65.54**	**25.74**	**62.76**	**62.52**

1. Combined operating netback data is based on weighted average of daily volume sold, which includes diluents necessary for the blending of the heavy 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, among others.
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. Corresponds to the net effect of the overlift position of $0.7 million income during the third quarter of 2014 ($12.6 million income for the second quarter of 2014).
5. 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.

Combined operating netback for the nine months to date remained strong at $60.44/boe, as summarized below.

	Year to Date					
	September 30, 2014			September 30, 2013		
	Crude Oil	Natural Gas	Combined	Crude Oil	Natural Gas	Combined
Average daily volume sold (boe/day)[1]	**135,130**	**10,384**	**145,514**	**116,786**	**10,743**	**127,528**
Operating netback ($/boe)						
Crude oil and natural gas sales price	96.70	31.69	**92.07**	100.36	38.84	**95.17**
Production cost of barrels sold [2]	16.52	3.67	**15.60**	15.41	5.41	**14.56**
Transportation (trucking and pipeline) [3]	14.70	(0.02)	**13.65**	15.01	0.13	**13.75**
Diluent cost	2.45	-	**2.28**	6.63	-	**6.07**
Total operating cost	**33.67**	**3.65**	**31.53**	**37.05**	**5.54**	**34.38**
Overlift/Underlift [4]	(1.68)	(0.05)	**(1.57)**	(1.51)	(0.02)	**(1.38)**
Other costs [5]	1.63	2.13	**1.67**	0.73	2.48	**0.89**
Total operating cost including overlift/underlift and other costs	**33.62**	**5.73**	**31.63**	**36.27**	**8.00**	**33.89**
Operating netback crude oil and gas ($/boe)	**63.08**	**25.96**	**60.44**	**64.09**	**30.84**	**61.28**

Notes: Refer to the operating netback table on page 6.

Combined operating costs for the quarter (before overlift and other costs) decreased to $30.79/boe for the quarter from $34.26/boe in the same period of 2013 and $31.71/boe in the second quarter of 2014, a year-on-year decline of 10%. Combined operating costs for the year to date (before overlift and other costs) decreased to $31.53/boe from $34.38/boe in the same period of 2013, a reduction of 8%.

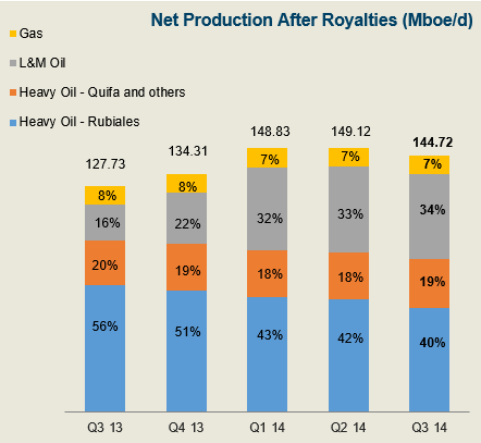
Since early 2013, the Company has been undertaking several initiatives to reduce oil operating costs. Diluent cost for the quarter decreased by $1.35/boe compared to the same period in 2013, achieved through the targeted acquisition of light crude that has been used to replace more expensive diluent purchased from third parties. Production cost decreased to $15.48/boe from $16.35/boe in the third quarter of 2013 and $15.75/boe in the second quarter of 2014. Transportation cost for the quarter decreased compared to the third quarter of 2013 as a result of a lower volume of oil being transported via tank truck. We have been able to maintain a low transportation cost despite the intermittent disruption of the Bicentenario Pipeline by diverting volumes to other pipelines through short-term agreements and by using tank trucks. The Bicentenario Pipeline was out of service for 41 days in the current quarter, compared to 80 days in the second quarter of 2014 and 52 days in the first quarter of 2014.

As a result of the increase in our sales from crude oil trading, volumes sold for the quarter rose to 15.1 MMboe from 11.4 MMboe in the third quarter of 2013 and 14.1 MMboe in the second quarter of 2014. Total realized price decreased to $88.38/boe from $97.54/boe in the third quarter of 2013 and $95.32/boe in the second quarter of 2014, mainly due to the ICE Brent decreasing by $6.30/bbl to $103.46/bbl as compared to $109.76/bbl in the second quarter of 2014, and by $6.19/bbl as compared to $109.65/bbl in the third quarter of 2013. Excluding trading volumes, realized price on sold equivalent barrels decreased to $88.05/boe from $97.29/boe in the same period of 2013 and $94.95/boe in the previous quarter of 2014.

3. Operational Results

Production and Development Review

Net production for the quarter averaged 144,722 boe/d, 13% higher than the 127,728 boe/d for the same quarter of 2013 and 3% lower than the second quarter of 2014. Compared to the second quarter of 2014, the decrease was mainly due to a modest drop in production from the Rubiales Field as a result of restricted water disposal capacity and unexpected weather conditions impacting operations. This reduction was partially offset by increases in production in Quifa SW.



We have significantly increased our light and medium oil production since 2013 through targeted acquisitions and exploration discoveries. Light and medium oil production increased from an average of 20,444 bbl/d for the third quarter of 2013 to 48,505 bbl/d for the current quarter, a 137% increase. Light and medium oil production now represents 34% of our total net oil and gas production, while production from the Rubiales Field now represents 40% of the total production, down from 56% for the same period of 2013.

The following table highlights the average daily production from all of the Company's producing fields located in Colombia and Peru:

	Average Q3 Production (in boe/d)						
	Total field production		Gross share before royalties [1]		Net share after royalties		
Producing fields - Colombia	**Q3 2014**	**Q3 2013**	**Q3 2014**	**Q3 2013**	**Q3 2014**	**Q3 2013**	**Q2 2014**
Rubiales / Piriri	175,012	210,640	72,939	89,035	58,351	71,228	63,482
Quifa SW [2]	58,091	55,997	34,437	33,331	23,750	22,994	22,543
	233,103	**266,637**	**107,376**	**122,366**	**82,101**	**94,222**	**86,025**
Other fields in Colombia							
Light and medium [3]	52,936	26,552	49,710	20,808	46,200	19,159	46,217
Gas [4]	11,412	11,183	10,269	10,509	10,269	10,509	10,362
Heavy oil [5]	5,793	4,455	4,059	2,716	3,847	2,553	3,973
	70,141	**42,190**	**64,038**	**34,033**	**60,316**	**32,221**	**60,552**
Total production Colombia	**303,244**	**308,827**	**171,414**	**156,399**	**142,417**	**126,443**	**146,577**
Producing fields in Peru							
Light and medium	4,739	2,623	2,305	1,285	2,305	1,285	2,541
	4,739	**2,623**	**2,305**	**1,285**	**2,305**	**1,285**	**2,541**
Total production Colombia and Peru	**307,983**	**311,450**	**173,719**	**157,684**	**144,722**	**127,728**	**149,118**

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 S.A. ("**Ecopetrol**").
3. Mainly includes Cubiro, Cravoviejo, Casanare Este, Canaguaro, Guatiquia, Casimena, Corcel, CPI Neiva, Cachicamo, Arrendajo and other producing fields. Also includes the interest in the Cubiro field acquired from LAEFM effective April 1, 2014 pursuant to a transaction that closed on August 12, 2014, which produced at 3,626 bbl/d. Subject to approval from Ecopetrol and the Agencia Nacional de Hidrocarburos ("**ANH**") (as and if applicable), the Company is in the process of divesting its participation in the Moriche, Las Quinchas, Guasimo, Chipalo, Cerrito, Yamu, Dindal/Rio Seco, Abanico and Carbonera blocks.
4. Includes La Creciente, Dindal / Rio Seco, Abanico, Cerrito, Carbonera and other producing fields.
5. Includes Cajua, Sabanero, CPE-6, Rio Ariari, Prospecto S and Prospecto D fields.

Colombia

During the third quarter of 2014, average net production after royalties in Colombia rose to 142,417 boe/d (303,244 boe/d total field production) from 126,443 boe/d (308,827 boe/d total field production) in the same period of 2013, representing an increase of 13%, with key developments as follows:

- Production commenced in the Canaguaro Block in the Llanos Basin with the drilling of one exploration well, which averaged 1,398 bbl/d during the quarter.
- 93 development wells were drilled during the third quarter of 2014.
- Net production at the Rubiales Field decreased 18% in comparison to the same period of 2013. Production reductions during the quarter at the mature Rubiales Field were primarily due to restricted water disposal capacity as a result of the impact of the abnormal weather conditions and delays in the permitting of the Agrocascada water irrigation project.

Peru

During the third quarter of 2014, average net production after royalties in Peru increased to 2,305 bbl/d (4,739 bbl/d total field production) from 1,285 bbl/d (2,623 bbl/d total field production) in the same period of 2013, which represented an increase of 79%.

The Los Angeles well commenced long-term production testing in September and is now producing on natural flow at 2,246 bbl/d of 45 °API oil with a 0.05% watercut. Two appraisal wells are expected to be drilled in the next 12 months to further evaluate the size and extent of the reservoir, as well as one exploration well targeting a separate prospect on the block.

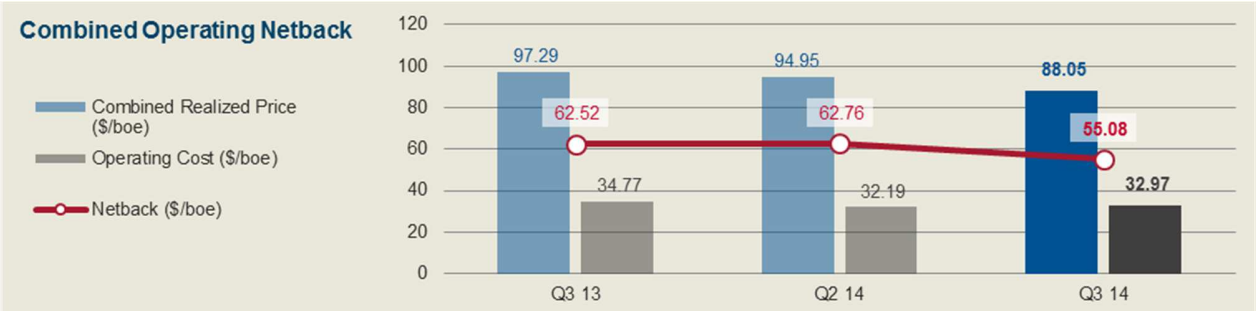
Sales, Trading and Pricing

The following table highlights the average daily crude oil and gas produced and available for sale, the trading volumes sold, and the respective realized and international prices:

	Average Volume of Sales and Prices		
Colombia and Peru	**Q3 2014**	**Q3 2013**	**Q2 2014**
Oil (bbl/d)	138,667	109,228	136,108
Gas (boe/d)	10,123	10,237	10,300
Trading (bbl/d)	14,827	4,224	8,619
Total barrels sold (in boe/d)	163,617	123,689	155,027
Realized Prices			
Oil realized price ($/bbl)	92.14	103.00	99.76
Gas realized price ($/boe)	31.95	36.35	31.33
Combined realized price oil and gas $/boe (excluding trading)	88.05	97.29	94.95
Trading realized price ($/bbl)	91.76	104.80	101.53
Reference Market Prices			
WTI NYMEX ($/bbl)	97.25	105.81	102.99
BRENT ICE ($/bbl)	103.46	109.65	109.76
Guajira Gas Price ($/MMBtu) [1]	5.66	5.73	3.97
Henry Hub average Natural Gas Price ($/MMBtu)	3.95	3.56	4.58

1. The domestic natural gas sales price is referenced to Market Reference Price ("**MRP**") for gas produced in La Guajira Field.

Total barrels sold is composed of production volumes, purchased diluent volumes, trading volumes and inventory balance changes. Sales volumes for the current quarter were a record 163,617 boe/d, an increase of 32% as compared to the 123,689 boe/d reported for the same period in 2013 and a 5% increase from the second quarter of 2014. This record volume of sales was mainly achieved due to higher sales from crude oil trading.



The combined realized oil and gas price for the third quarter of 2014 was $88.05/boe, $6.90/boe lower as compared to that of the second quarter of 2014 ($94.95/boe). Average WTI prices decreased by $5.74/bbl to $97.25/bbl in the third quarter of 2014 from $102.99/bbl in the second quarter of 2014. In addition, WTI prices decreased by $8.56/bbl as compared to the third quarter of 2013 ($97.25/bbl from $105.81/bbl). Similarly, ICE Brent decreased by $6.30/bbl to $103.46/bbl as compared to $109.76/bbl in the second quarter of 2014, and by $6.19/bbl as compared to the third quarter of 2013 ($103.46/bbl from $109.65/bbl). As a consequence the ICE Brent – WTI Nymex differential narrowed by $0.56/bbl during the third quarter of 2014 ($6.21/bbl from $6.77/bbl) compared to the second quarter of 2014 and widened by $2.37/bbl ($6.21/bbl from $3.84/bbl) compared to the third quarter of 2013.

Exploration Review

During the third quarter of 2014, fourteen wells were drilled in Colombia and Peru consisting of seven exploration wells, five appraisal wells and two stratigraphic wells. Drilling resulted in a new discovery in the Canaguaro Block and further confirmation and appraisal delineation of the discoveries on the Guatiquía, Albacora, Río Ariari and CPE–6 Blocks.

	Three Months Ending September 30		Nine Months Ending September 30	
	2014	2013	2014	2013
Successful exploratory wells	4	3	7	10
Successful appraisal wells [1]	5	-	18	1
Successful stratigraphic wells	2	-	3	-
Dry wells	3	-	11	5
Total	**14**	**3**	**39**	**16**
Success rate	**79%**	**100%**	**72%**	**69%**

1. Includes horizontal appraisal wells.

Colombia

Rio Ariari Block

Three wells were drilled on the Rio Ariari Block, one vertical and two horizontal. The horizontal wells in the Mochelo and Heliconia discoveries were drilled with 437 feet and 693 feet of horizontal section respectively. All three wells tested oil with varying rates of water, consistent with previous wells drilled into the fields. Well results, including petrophysical analysis, are currently being evaluated as part of the broader field delineation and will be incorporated into the field's development plans.

Guatiquía Block

Continuing with evaluation of the very successful exploration potential in the Guatiquia Block, the Ardilla-1 well spudded during the third quarter of 2014. The well reached TD of 12,825 feet on October 19. Encouraging indicators of hydrocarbons were encountered during drilling in the Lower Sand 1, Guadalupe and Mirador Formations. Petrophysical interpretation indicates the presence of 71 feet of net pay including seven feet in the Mirador, 17 feet in the Guadalupe and 44 feet in the Lower Sandstone-1 Unit (with no water contact present), very similar to the Ceibo-1X well, which was successfully drilled earlier in 2014. The well will be cased and tested in the Lower Sandstone-1 Unit.

Canaguaro Block

The Tapiti-1X appraisal well encountered approximately 24 feet of net pay in the Mirador formation based on logging while drilling ("**LWD**") logs. The well was completed in the upper 4 feet of Mirador Formation with an electrical submersible pump.

The well is currently producing at a stable rate of 1,346 bbl/d of 26.7 °API oil with a 20% water cut. Since its discovery, the well has produced a total of 22,120 barrels of oil.

Guama Block

In the Guama Block, the Company started extended tests of the Pedernalito – 1X on September 23, and by September 30 the well was producing 1.77 MMcf/d and 177 bbl/d of condensate (for a total of 475 boe/d). The Company also finished installation of a 5 MMcf/d gas plant with continued civil works and logistical preparations for the extended tests of Cotorra-1X, Manamo-1X and Capure-1X discovery wells.

Quifa Block

In the Quifa Block, two exploration wells were drilled in the eastern portion of the block. The QFE-B-2 did not encounter any pay and was plugged and abandoned. The QFE-S-2 encountered 7 feet of net pay in the Basal Sands, confirming the accumulation to the east in Prospect S. The well was completed with an oil production of 30 bbl/d. The interpretation of the recently acquired 3D seismic in the northwestern portion of the block has also confirmed the adjacent exploration potential along the Jaspe discovery and revealed additional exploration prospect to the south of the Cajua Field.

CPO17 Block

In Block CPO17 (in which PRE has a 25% working interest), the stratigraphic well CPO17-EST-10 was drilled to investigate the possible extension of the accumulation in the Godric Field. Petrophysical evaluation indicated a finding of 25 feet of net pay in the Mirador Formation. The well is located 3 km and 7 km to the west of the previously drilled CPO17-EST-12 and CPO17-EST-13 respectively, confirming the potential of the Godric Field. CPO17-EST-10 had the fastest oil flow during the

sampling of all the wells in the block. There is evidence on well logs to infer a hydraulic separation between the oil pay and the free water zones, confirming the importance of this find.

Peru

The Los Angeles-1X well in Block 131 (in which PRE has a 30% working interest) is a significant oil discovery in the Ucayali Basin in onshore Peru. The well reached TD in late 2013. Petrophysical evaluation indicated the presence of 62 feet of net pay in the Cretaceous-aged Cushabatay Formation. A 30-day production test was conducted across different net pay intervals to understand the drive mechanism and flow characteristics of the reservoir. Based on this initial test, the operator (Cepsa Peru S.A.) planned a long-term extended production test to be carried out as soon as permits and test logistics were allowed. The extended production test commenced on September 18, 2014 and is expected to continue for a six month period.

As of October 23, 2014, the well was producing 2,258 bbl/d of 45° API oil with a 0.05% watercut, a gas-oil ratio of 27 cf/bbl on a 28/64" choke with a wellhead pressure of 311 psi on natural flow. Since the extended production test commenced, the well has produced over 61 Mbbl of oil (over 109 Mbbl of total cumulative oil, including earlier tests). Production from the Los Angeles-1X well is being trucked approximately 95 km and sold to the nearby Pucallpa refinery in Peru. Over the next 12 months, the operator plans to drill two appraisal wells on the Los Angeles discovery to further evaluate the size and extent of the reservoir with an additional exploration well targeting a separate prospect on the block. Both the operator and the Company are currently evaluating longer-term development and marketing strategies for Block 131.

The Company drilled the Fortuna-1X ST3 exploration well in the onshore Peru Block 116 (in which PRE has a 50% working interest) during the quarter. The well was targeting limestone and sandstone reservoirs in the Cretaceous Vivian and Cushabatay formations. As a result of operational challenges these targets were not reached and the Company decided to abandon the lower section and test the one Tertiary interval with oil and gas shows. Two more test intervals are contingent on the results of the first test.

The Albacora Field located in offshore Peru in Block Z-1 (49% working interest) has traditionally produced from the Early Miocene Middle Zorritos sandstones at a depth of approximately 10,000 feet. Reinterpretation of 3D seismic data acquired in 2012 indicates the presence of a new play (named the MZA, MZB and MZC units) located some 1,000 to 2,000 feet deeper than the Zorritos producing pools. Four wells (A-18DST, A-26D, A-19D and A-21D) were drilled during 2014 targeting these units. Three wells were successful in these new zones and they are either on production or being brought on to production. The Company and its partner, BPZ Energy, are currently drilling the A-27D to test both the Zorritos and deeper units and expect to reach TD in this well by year-end 2014.

Guatemala

Efforts in this quarter had three objectives: (a) receiving approvals of the 2014-2015 Work Plan and Budget, from the Ministry of Energy and Mines, (b) designing and design optimization of the next exploration well (Choma-1X) to be spudded during the fourth quarter of 2014 and (c) contracting all the goods and services needed for the drilling and testing of the Choma-1X well.

Belize

The original design of the 2D seismic survey (650 km) was reduced to 344 km and the survey is 86% complete with the seismic interpretation expected by mid-2015.

Papua New Guinea

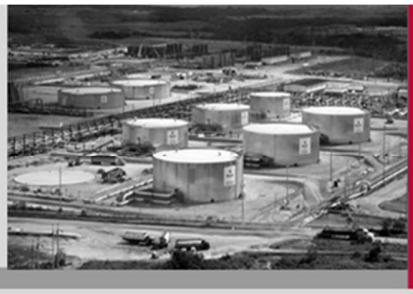
In Block PRL-39 (in which PRE has a 12.9% net participating interest) in Papua New Guinea, the operator InterOil Corporation ("**InterOil**"), spudded the Raptor-1 exploration well in late March. The Raptor prospect is located approximately 12 km west of InterOil's Elk-Antelope natural gas Field. The Raptor-1 well has intersected 656 feet of the Kapau Limestone target zone with wireline logs indicating the presence of hydrocarbons. The operator now plans to conduct well testing operations to determine the hydrocarbon type, flow rate and reservoir quality.

Farm-in Transactions and Acquisitions

Cubiro and Arrendajo Blocks

During the three months ending September 30, 2014, the Company completed the acquisition of the remaining interests in the Cubiro Block and the Arrendajo Block in Colombia that it did not already own, from LAEFM Colombia Ltda ("**LAEFM**"). The transactions were completed upon the signing of the definitive agreements for Cubiro and Arrendajo on August 12 and September 15 of 2014, respectively, which are deemed under IFRS 3 to be the dates on which the business combination occurred. Notwithstanding the above, the signed agreements specify that revenues and costs corresponding to LAEFM's interests were legally transferred to the Company effective April 1, 2014 for Cubiro and July 1, 2014 for Arrendajo. Prior to the completion of this acquisition, Cubiro and Arrendajo were recognized as joint operations pursuant to certain private participation agreements previously entered into by the Company with LAEFM. The consideration for the two transactions consisted of $250 million in cash, as well as contingent consideration of $21.93 per barrel of proven and probable oil reserves upon the certification of certain areas on the Cubiro Block as at December 31, 2014.

The transaction is being accounted for as a business combination with the Company identified as the acquirer. As Cubiro and Arrendajo were previously recognized as joint operations, at the time of acquisition of control the previous carrying amounts were considered to have been disposed of at their fair value, resulting in a net gain of $40.3 million recognized in other income (expense) on the consolidated financial statements. In addition, 100% of the blocks are considered to have been acquired immediately



Revenues

(in thousands of US$)	Three Months Ending September 30 2014	Three Months Ending September 30 2013	Nine Months Ending September 30 2014	Nine Months Ending September 30 2013
Net crude oil and gas sales	$ 1,205,227	$ 1,069,245	$ 3,657,429	$ 3,313,485
Trading revenue	125,168	40,728	301,085	110,823
Total Revenue	**$ 1,330,395**	**$ 1,109,973**	**$ 3,958,514**	**$ 3,424,308**
$ per boe oil and gas	88.05	97.29	92.07	95.17
$ per bbl trading	91.76	104.80	97.09	102.06
$ Total average revenue per boe	**88.38**	**97.54**	**92.43**	**95.38**

	Three Months Ending September 30 2014	2013	Difference	%Change
Total of boe sold (Mboe)	15,053	11,379	3,674	32%
Avg. combined price - oil & gas and trading ($/boe)	88.38	97.54	(9.16)	-9%
	1,330,395	**1,109,973**	**220,422**	**20%**

The following is an analysis of the revenue drivers for the third quarter of 2014 in comparison to the same period of 2013:

Drivers for the revenue increase:		
Due to volume	$ 358,307	163%
Due to price	(137,885)	-63%
	$ 220,422	

Revenues for the third quarter of 2014 were $1.33 billion, 20% higher as compared to the same period of 2013 and mainly driven by higher sales volumes but partially offset by lower realized prices. Year-to-date revenue from oil and gas sales increased by over 16% to $3.96 billion from $3.42 billion in 2013, despite the challenge of a decline in world oil prices through the third quarter.

Operating Costs

(in thousands of US$)	Three Months Ending September 30 2014	Three Months Ending September 30 2013	Nine Months Ending September 30 2014	Nine Months Ending September 30 2013
Production cost of barrels sold	$ 211,878	$ 179,732	$ 619,723	$ 507,163
Per boe	15.48	16.35	15.60	14.56
Transportation cost	180,145	158,377	542,175	478,910
Per boe	13.16	14.41	13.65	13.75
Diluent cost	29,370	38,468	90,581	211,431
Per boe	2.15	3.50	2.28	6.07
Overlift/Underlift	(794)	(13,738)	(62,329)	(48,108)
Per boe	(0.06)	(1.25)	(1.57)	(1.38)
Other cost	30,723	19,344	66,175	30,611
Per boe	2.24	1.76	1.67	0.89
Operating cost	**$ 451,321**	**$ 382,182**	**$ 1,256,325**	**$ 1,180,007**
Average operating cost per boe	**$ 32.97**	**$ 34.77**	**$ 31.63**	**$ 33.89**
Take-or-pay fees on disrupted transport capacity Bicentenario	21,921	-	75,625	-
Per boe	1.60	-	1.90	-
Trading purchase cost	125,034	40,158	299,411	108,907
Per boe	91.66	103.33	96.55	100.30
Total Cost	**$ 598,276**	**$ 422,340**	**$ 1,631,361**	**$ 1,288,914**

Total operating costs for the third quarter of 2014 and on a year-to-date basis were $598 million and $1.63 billion respectively, including $22 million during the quarter and $76 million year to date in net take-or-pay fees paid to Oleoducto Bicentenario de Colombia S.A.S. ("**Bicentenario**") when the capacity was not available due to security issues. Operating costs were higher as compared to $422 million and $1.29 billion for the same periods of 2013 as a result of an increase in oil and gas produced and higher other costs and overlift movement. Total cost for the third quarter of 2014 was $32.97/boe, lower by 5% as compared to $34.77/boe for the same period of 2013. On a year-to-date basis, total cost for the period of 2014 was $31.63/boe, lower by 7% as compared to $33.89/boe for the same period of 2013. In addition, trading purchase cost increased from $40 million in the third quarter of 2013 to $125 million and from $109 million to $299 million on a year-to-date basis, mostly due to higher volumes sold during the period.

Depletion, Depreciation and Amortization

	Three months ending September 30		Nine Months Ending September 30	
(in thousands of US$)	2014	2013	2014	2013
Depletion, depreciation and amortization	$ 407,280	$ 369,778	$ 1,165,625	$ 1,034,787
$/per boe sales (own production)	29.75	33.64	29.34	29.72

Depletion, depreciation and amortization ("**DD&A**") costs for the quarter and year-to-date 2014 were $407 million and $1.17 billion, respectively compared to $370 million and $1.03 billion in the same periods of 2013. The increase of 10% and 13% over 2013 was primarily due to an increase in production and higher capitalized costs that are subject to depreciation. Unit DD&A for the quarter and year-to-date of 2014 were $29.75/boe and $29.34/boe, 12% and 1% lower than the $33.64/boe and $29.72/boe for the same periods of 2013, respectively. As a result of additions of 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 reserves pool. The reduced depletion due to the larger reserve pool is partially offset by the fact that during the quarter, the Company acquired an additional working interest in Cubiro and Arrendajo Fields resulting in higher DD&A cost during the quarter.

General and Administrative Costs

	Three months ending September 30		Nine Months Ending September 30	
(in thousands of US$)	2014	2013	2014	2013
General and administrative costs	$ 97,040	$ 75,500	$ 262,344	223,764
$/per boe sales	6.45	6.63	6.13	6.23

General and administrative ("**G&A**") costs increased to $97 million and $262 during the three- and nine-months periods of 2014 from $76 million and $224 million in the same periods of 2013, mainly due to expanded operations and production. Unit G&A costs decreased by $0.18/boe from $6.63/boe to $6.45/boe compared to the three months that ended on September 30, 2013 and decreased by $0.10/boe from $6.23/boe to $6.13/boe for the nine months that ending September 30, 2013 a decrease resulting from the increase in overall production and sales.

Finance Costs and Foreign Exchange

	Three months ending September 30		Nine Months Ending September 30	
(in thousands of US$)	2014	2013	2014	2013
Finance costs	$ 61,412	$ 34,451	$ 187,562	$ 119,104

Finance costs include interest on the Company's bank loans, senior notes, revolving credit facilities, working capital loans, finance leases and fees on letters of credit, net of interest income received. For the quarter and year-to-date 2014, interest expenses totaled $61 million and $188 million compared to $34 million and $119 million for the same periods of 2013. The increase in finance costs is mainly due to issuance of additional senior unsecured notes, with an aggregate principal of $4.1 billion as at September 30, 2014 compared to $2.0 billion as at September 30, 2013.

	Three months ending September 30		Nine Months Ending September 30	
(in thousands of US$)	2014	2013	2014	2013
Foreign exchange gain (loss)	$ (22,841)	$ 767	$ (10,972)	$ 9,203

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 the third quarter of 2014, the COP depreciated against the U.S. dollar by 8% as compared to an appreciation of 0.74% during the same period of 2013. Foreign exchange expense for the third quarter of 2014 was $23 million compared to a gain of $0.8 million for the same period of 2013. The foreign exchange loss for the third quarter of 2014 was mainly due to unrealized foreign exchange translation losses from the translation of COP-denominated balances into the U.S. dollar.

Income Tax Expense

	Three Months Ending September 30		Nine Months Ending September 30	
(in thousands of US$)	2014	2013	2014	2013
Current income tax	$ 7,898	$ 109,116	$ 268,133	$ 371,779
Deferred income tax	171,580	(20,983)	100,200	13,968
Total income tax expense	**$ 179,478**	**$ 88,133**	**$ 368,333**	**$ 385,747**
$ per boe	11.92	7.74	8.60	10.74

The Canadian statutory combined income tax rate was 26.5% for the third quarter of 2014 and 2013.

The Colombian statutory tax rate for the third quarter of 2014 was 34%, which includes the 25% general income tax rate and the fairness tax ("**CREE**") at 9%.

The Peruvian statutory income tax rate was 30% for the third quarter of 2014 and 2013. The Peruvian income tax rate for Block Z-1 was 22% for the third quarter of 2014 and 2013.

The Company's effective tax rate (income tax expenses as a percentage of net earnings before income tax) was 98% for the third quarter of 2014 compared to 51.7% for the same period in 2013. For the nine-month period ending September 30, 2014, the cumulative effective tax rate was 51.3% compared to 58.1% over the same cumulative period ending September 30, 2013.

The Company's effective tax rate is subject to fluctuations in the COP exchange rate against the U.S. dollar. Since the Company's oil and gas assets are primarily located in Colombia, the tax base of these assets is denominated in COP, and the related deferred tax balances are revalued periodically to reflect the closing U.S.$-COP exchange rate in accordance with IFRS. Any movement in the exchange rate results in a corresponding unrealized exchange gain or loss being recorded as part of deferred income tax expense or recovery. During periods when there have been large fluctuations in the U.S.$-COP exchange rate, these amounts may be significant but are unrealized and may reverse in the future.

Excluding the effect from the above-mentioned foreign exchange fluctuations, the effective tax rate for the Company would be 46.9% and 41.5% for the three-and nine-months periods that ended September 30, 2014, respectively:

	Three Months Ending September 30		Nine Months Ending September 30	
(in thousands of US$)	2014	2013	2014	2013
Appreciation (depreciation) of the COP against U.S. dollar (%)	(7.8)%	0.7%	(5.3)%	(8.3)%
Net earnings before income tax	$ 182,638	$ 170,426	$ 718,229	$ 664,193
Current income tax expense	(7,898)	(109,116)	(268,133)	(371,779)
Deferred income tax (expense) recovery as reported	(171,580)	20,983	(100,200)	(13,968)
Total income tax expense as reported	**(179,478)**	**(88,133)**	**(368,333)**	**(385,747)**
Exclude effect from revaluation of COP	93,786	(1,423)	69,965	78,925
Total income tax expense excluding the above effects	**(85,692)**	**(89,556)**	**(298,368)**	**(306,822)**
Effective tax rate excluding effect of COP revaluation	**46.9%**	**52.5%**	**41.5%**	**46.2%**

The company is taking measures to accelerate the deductions related to certain oil & gas assets, which should result in a lower current tax rate and a higher deferred tax rate.

In addition to the above, 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, but 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.

Capital Expenditures

	Three Months Ending September 30		Nine Months Ending September 30	
(in thousands of US$)	2014	2013	2014	2013
Production facilities [1]	$ 157,210	$ 154,709	$ 380,095	$ 441,385
Exploration activities [2]	134,671	87,094	387,658	259,181
Early facilities and others	58,936	-	128,560	-
Development drilling [1]	268,424	142,089	647,829	445,057
Other projects (STAR, Gas export, PEL)	26,071	38,533	80,312	105,785
Total capital expenditures	**$ 645,312**	**$ 422,425**	**$ 1,624,454**	**$ 1,251,408**

1. Includes investment in Maurel & Prom Colombia B.V., in which the Company holds a 49.999% participation.
2. Exploration activities for the third quarter of 2014 include drilling, seismic and other geophysical expenditures in Colombia, Peru, Brazil, Guatemala, Belize, and Papua New Guinea.

Capital expenditures during the third quarter of 2014 totaled $645 million, higher by $223 million as compared to $422 million in the third quarter of 2013. A total of $157 million was invested in the expansion and construction of production infrastructure, primarily in Rubiales, Quifa SW, Cubiro, Casanare Este, Guama, Cravoviejo, Sabanero, La Creciente, and in the Block Z-1 Fields; $135 million went into exploration activities including drilling, seismic and other geophysical activities in Colombia, Peru, Brazil, Guatemala, Belize and Papua New Guinea; $59 million was included in early facilities and others; $268 million went into development drilling; $26 million was invested in other projects including the small-scale LNG project and the Petroelectrica de los Llanos ("**PEL**") Power Transmission Line project.

In light of the current weaker commodity price environment, we are evaluating all our capital programs. Our diversified portfolio of assets has the flexibility and discretionary components to allow us to scale back capital spending while maintaining production growth. Our previous guidance for 2014 was $2.5 billion in E&P expenditures – we now expect that this number will be closer to $2.3 billion, as we compensate for annual production at the low end of our guidance and lower world oil prices in the second half of 2014. The Company will allocate capital spending on the highest return, most material projects in our portfolio.

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

	Three Months Ending September 30		Nine Months Ending September 30	
(in thousands of US$)	2014	2013	2014	2013
Farm-in Agreement and others [1]	276,779	36,092	289,279	301,765
Total capital expenditures for new acquisitions	**276,779**	**36,092**	**289,279**	**301,765**

1. For the third quarter of 2014, includes the acquisition of the remaining interest in Cubiro and Arrendajo Fields. In the third quarter of 2013, includes block acquisition costs in Brazil and Peru ($33 million) and other related costs ($3 million).

Financial Position

Debts and Credit Instruments

The following debts were outstanding as at September 30, 2014:

Senior Unsecured Notes

The Company has a number of senior unsecured notes outstanding with an aggregate principal of $3.3 billion outstanding as at September 30, 2014. The senior notes are listed on the Official List of the Luxembourg Stock Exchange and are guaranteed by the Company's main operating subsidiaries. The maturities of the senior notes range from 2019 to 2025 and the interest rates range from 5.125% to 7.25%, payable semi-annually.

During the quarter, the Company closed a $750 million offering of 5.625% senior unsecured notes due 2025 ("**5.625% Senior Notes**"). The Company also closed an exchange offer (the "**Exchange Offer**") of its 7.25% senior unsecured notes due 2021 ("**7.25% Senior Notes**"). The Exchange Offer resulted in $321.6 million aggregate principal amount of 7.25% Senior Notes being validly tendered and accepted for exchange into 5.625% Senior Notes.

The Exchange Offer commenced on September 19, 2014 and ended on October 17, 2014. Eligible holders of 7.25% Senior Notes who tendered prior to 5:00 p.m. (New York time) on October 2, 2014 received (the "**Early Expiration Date**"), in exchange for each U.S.$1,000 of principal amount of 7.25% Senior Notes exchange, an aggregate principal amount of 5.625% Senior Notes equal to $1,131.25. Eligible holders who tendered their 7.25% Senior Notes after the Early Expiration Date but prior to 11:59 p.m. (New York time) on October 17, 2014 received, in exchange for each U.S.$1,000 of principal amount of 7.25% Senior Notes exchanged, an aggregate principal amount of 5.625% Senior Notes equal to U.S.$1,101.25 on the final settlement date.

Working Capital Loans

From time to time, the Company maintains working capital facilities with several banks. As of September 30, 2014, our current facilities are with Citibank, N.A., Bank of America, N.A., JPMorgan Chase Bank, N.A., Itau BBA, Bank of Tokyo and Mercantil Commerce Bank, N.A. The terms of these loans are generally less than a year. As at September 30, 2014, we did not have any borrowings outstanding under these working capital facilities.

Letters of Credit

As at September 30, 2014, the Company had issued letters of credit and guarantees for exploration and operational commitments for a total of $471 million.

Outstanding Share Data

Common Shares

As at November 5, 2014, 316,091,858 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 November 5, 2014, there were no warrants outstanding. 23,235,292 stock options were outstanding, of which all were exercisable. As of May 28, 2014, the Board has committed to no longer granting stock options and instead has implemented a Deferred Share Unit ("**DSU**") Plan for eligible employees.

Deferred Share Units

As at November 5, 2014, there were 2,230,092 DSUs outstanding. The DSUs are cash settled instruments that track the price of the common shares and are payable to eligible participants upon their retirement, resignation or termination from the Corporation.

Liquidity and Capital Resources

Funds flow provided by operating activities for the third quarter of 2014 totaled $606 million ($455 million in the same period of 2013). The increase in funds flow for the third quarter of 2014 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 expects this to continue and increase with production growth.

As of September 30, 2014, the Company had negative working capital of $416 million, mainly comprised of $478 million of cash and cash equivalents, $1 million in restricted cash, $1.02 billion of account receivables, $83 million of inventory, $98 million of income tax receivable, $1.89 billion of accounts payable and accrued liabilities, $30 million of income tax payable, $158 million of the current portion of long-term debt and $18 million of the current portion of obligations under finance lease.

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 September 30, 2014, our current facilities are with Citibank, N.A., Bank of America, JPMorgan Chase Bank, N.A., Itau, Bank of Tokyo, HSBC, and Mercantil Commerce Bank, N.A. The terms of these loans are generally less than a year.

As at September 30, 2014, the Company had no outstanding balance under these working capital facilities.

5. Project Status Review

The following is an update on the current status and working-interest share of costs incurred as of September 30, 2014 for the Company's major projects:

		As of September 30, 2014		
Project	**Project financed by**	**Total cost to complete the project**	**Cost incurred to date**	**Expected future costs to incur**
Bicentenario pipeline	Equity and debt combination	804,661	661,371	143,290
PEL-Power transmission line project	Equity and debt combination	240,000	208,390	31,610
Small-scale LNG project	Equity and debt combination	278,126	27,946	250,180
Water treatment for agricultural development	Equity and debt combination	170,000	90,000	80,000
Puerto Bahia project	Equity and debt combination	239,439	161,532	77,907
OLECAR	Equity and debt combination	160,442	36,116	124,326
		$ 1,892,668	**$ 1,185,355**	**$ 707,313**

Bicentenario Pipeline

As of September 2014, Phase One of the project is complete and approximately 12.54 MMbbl has been pumped through the system. During the current quarter, the pipeline transported at an average rate of 45,813 bbl/d.

PEL – Power Transmission Line Project

The power line commenced operation on January 20, 2014, and as of September 30, 2014, the line had transmitted 563,561 MWh to Rubiales and Quifa Fields and to the ODL pipeline. As of the date of this report, the progress for the construction of the substations are as follows: Quifa substation construction was 87% complete and is expected to be operational by the fourth quarter of 2014, Jagüey substation is 55% complete and is expected to be complete in the first quarter of 2015, and the Corocora substation is 51% completed and is expected to be finished by the third quarter of 2015.

The results from studies to increase transmission capacity from 192 MW to 262 MW have been approved by Empresa de Energía de Bogotá and have been filed with the Unidad de Planeación Minero Energética ("**UPME**") for its approval. This increase in capacity will allow further future developments in the Llanos Basin.

The environmental alternative analysis and land surveys are in progress and environmental permits are expected to be filed with the corresponding authorities in the fourth quarter of 2014. The completion of the conceptual engineering for the power transmission line to the CPE-6 block was moved to 2015 based on the results of the environmental impact study.

Caribbean Floating LNG Project ("FLNG")

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 ("**LNG**") 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, Liquefaction and Storage Unit ("**FLSU**"). The FLSU will be connected to a Floating Storage Unit ("**FSU**") in order to allow FOB exports to standard carriers (130,000 to 150,000 CBM). Caribbean FLNG will be the first small-scale floating liquefaction plant worldwide. The project was nominated for an innovation prize at the last LNG World Summit.

As of September 2014, basic and detailed engineering for the gas pipeline and the offshore jetty has been completed. Port concession terms for the LNG terminal have been released, clarifications have been resolved to the ANLA about the environmental permits for onshore pipelines and are expected to receive a positive response for the environmental license next November 2014. The construction of the FLSU is underway in China, and is 92% completed.

Water Treatment for Agricultural Development

As of September 2014, the construction of the reverse osmosis water treatment plants reached 78% completion and the planting plan was completed for the year, with 14,022 plants in 1,300 ha planted for a cumulative total of 2,700 ha.

In August 2014 the Company received the ANLA approval for the delivery of water suitable for irrigation, which was filed on September 13, 2013. The permits for the agricultural component were filed with the environmental authority Cormacarena and the response is expected in November 2014.

This project represents an innovative approach for water disposal in Colombia. It brings benefits to oil producers in terms of lower operating costs and extending the economic life of the oil fields, and is also an excellent example of "shared value" with communities, bringing sustainable development from a social point of view to areas in need of development. The concept will be replicated by the Company in future developments in oil fields with high water-production rates.

Pacific Infrastructure: Puerto Bahía Terminal and Olecar Pipeline

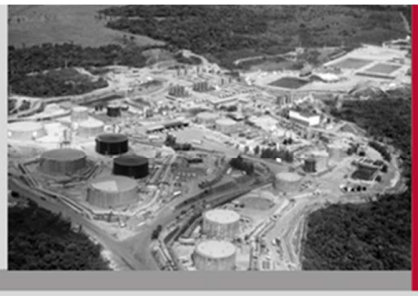
As of September 30, 2014, the Company had a 41.65% interest in Pacific Infrastructure Ventures Inc. ("**Pacific Infrastructure**"), a private company that is currently developing Puerto Bahía, an oil export terminal located in Cartagena Bay in Colombia. Puerto Bahía will be developed in three phases: (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, containers and a berthing platform with a length of 300 metres to handle dry materials.

As of September 30, 2014, construction activities have had the following progress: the liquids terminal has reached 79% completion, the truck loading and unloading station is at 64% completion, the fixed bridge was 100% completed in March 2014, and the multi-purpose terminal handling bulk materials has reached 64% completion.

Recognizing the strategic importance of the Puerto Bahía Terminal, Pacific Infrastructure signed an O&M agreement with Oiltanking International ("**Oiltanking**"). Oiltanking is recognized globally as a world-class operator of large-scale liquids terminals. During the third quarter of 2013, Pacific Infrastructure signed a credit agreement with Itau for $370 million, which was closed on February 25, 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 third largest refinery in Colombia, and Puerto Bahía.

As of the date of this report, environmental permits for the Olecar pipeline have been granted by the ANLA and right-of-way negotiations are in progress. Engineering for the Coveñas and Reficar stations are completed as well as the detailed engineering for the pipeline. Purchase orders for long-lead items are almost complete, including valves and main pumps, and corrosion protection and coating for the pipe received was completed successfully. The Olecar project is currently 34% complete.



6. 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 officially reassessed several value-added tax ("**IVA**") declarations on the basis that the volume of oil produced and used for internal consumption at certain fields in Colombia should have been subject to IVA. For the third quarter of 2014, the new amount reassessed, including interest and penalties, is estimated at $55.5 million. The Company disagrees with the DIAN's reassessment and official appeals have been initiated. Several other taxation periods back to 2011 with respect to IVA on field oil consumption are also 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 $31.9 million and $60.9 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 with respect to the special tax benefit for qualifying petroleum assets as well as other exploration expenditures. As of the date of this report, the DIAN has reassessed $73.5 million of tax owing, including estimated interest and penalties, with respect to the denied deductions.

As of September 30, 2014, 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 is currently in discussion with the ANH with respect to the interpretation of the high-price participation clause in certain exploration contracts. Please refer to "PAP Disagreement with the ANH" on page 26 for details relating to this contingency.

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.

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

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.

Disclosures concerning the Company's risk management contracts can be found in Note 25 of the Interim Condensed Consolidated Financial Statements.

7. 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. The board of directors of the Company has created the New Business Opportunities Committee ("**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 cross-referenced 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) During the three and nine months ending September 30, 2014, the Company paid $2.1 million and $6.8 million (2013: $4.9 million and $27.7 million) to Transportadora Del Meta S.A.S. ("**Transmeta**") in crude oil transportation costs. In addition the Company has accounts receivable of $1.3 million (December 31, 2013: $1.5 million) from Transmeta and accounts payable of $0.9 million (December 31, 2013: $1.7 million) to Transmeta as at June 30, 2014.Transmeta is controlled by German Efromovich, a director of the Company.

b) As at September 30, 2014, the Company had trade accounts receivable of $7.4 million (December 31, 2013: $0.2 million) from Promotora de Energia Electrica de Cartagena & Cia S.C.A.E.S.P ("**Proelectrica**"), in which the Company has a 24.9% indirect interest and which is 31.49% owned by Blue Pacific Assets Corp. ("**Blue Pacific**"). The Company and Blue Pacific have indirect interests held through Pacific Power. Revenue from Proelectrica in the normal course of the Company's business was $4.2 million and $11.2 million for the three and nine months that ended September 30, 2014 (2013: $4.9 and $26.8 million respectively).

   Three directors and officers, as well as an executive officer of the Company (Serafino Iacono, Miguel de la Campa, José Francisco Arata and Laureano von Siegmund) control, or provide investment advice to the holders of 78% of the shares of Blue Pacific.

c) 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 three and nine months ending September 30, 2014 those assets were under construction and the Company paid cash advances of $9.0 million and $9.0 million, which were recorded in other assets (2013: $0.6 million and $10.5 million). The Company has accounts payable of $3.0 million (December 2013: $0.4 million) due to Genser-Proelectrica. In addition, On May 5, 2014, a subsidiary of the Company provided a guarantee in favour of XM Compania de Expertos en Mercados S.A. on behalf of Proelectrica guaranteeing obligations pursuant to an energy supply agreement in the aggregate amount of approximately $16.7 million. The Company has a 24.9% indirect interest in Proelectrica.

d) In June 2007, the Company entered into a 5-year lease agreement with Blue Pacific for administrative office space in one of its Bogota, Colombia locations. Monthly rent expense of $0.087 million was payable to Blue Pacific under this agreement. Three directors and officers of the Company control, or provide investment advice to the holders of, 78% 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. Effective January 1, 2014, Blue Pacific ceased to be a party to the lease agreements upon assigning the rights under these agreements to a third party that is not related to the Company.

e) The Company has entered into aircraft transportation agreements with Helicopteros Nacionales de Colombia S.A.S. ("**Helicol**"), a company controlled by German Efromovich, a director of the Company. During the three and nine months ended September 30 2014, the Company paid $5.5 million and $11.5 million (2013: $4.4 million and $11.3 million) in fees as set out under the transportation agreements. As at September 30, 2014, the Company had accounts payable of $3.1 million to Helicol. (December 31, 2013: $2.5 million).

f) During the three and nine months ended September 30, 2014, the Company paid $57.9 million and $121.1 million to ODL (2013: $38.9 million and $99.4 million) for crude oil transport services under the pipeline take or pay agreement, and has accounts payable of $7.0 million to ODL as at September 30, 2014 (December 31, 2013: $7.4 million). The Company received $0.7 million and $1.7 million from ODL during the three and nine months ended September 30, 2014 (2013: $0.2 million and $0.7 million) with respect to certain administrative services and rental equipment and machinery. The Company accounts receivable from ODL as at September 30, 2014 $0.4 million (December 31, 2013: $0.1).

g) During the three and nine months ending September 30, 2014, the Company paid $44.9 million and $132.5 million to Bicentenario (2013: Nil and $38.5 million), a pipeline company in which the Company has a 43% interest, for crude oil transport services under the pipeline take-or-pay agreement. As at September 30, 2014 the balance of loans outstanding to Bicentenario under the agreement in note 16 (other assets), is $42 million (December 31, 2013: $42 million). Interest income of $0.7 million and $2.1 million was recognized during the three and nine months ended September 30, 2014 (2013: $0.5 million and $1.5 million). Interest of $5.9 million was paid on the loans during the three months ending September 30, 2014. The Company has received Nil and $0.5 million during the three and nine months ending September 30, 2014 (2013: Nil and $0.7 million) with respect to certain administrative services and rental equipment and machinery. The Company has accounts receivable from Bicentenario as at September 30, 2014 of $42 million (December 31, 2013: $42 million) and advanced $97.4 million to September 30, 2014 (December 31, 2013: $90 million) to Bicentenario as a prepayment of transport tariff, which is amortized against the barrels transported. As of September 30, 2014, the Company has a receivable from Bicentenario of $20 million representing the return of a portion of the tariffs paid during the period of disrupted pipeline service.

h) The Company has established one charitable foundation in Colombia, the Pacific Rubiales Foundation, with the objective of advancing social and community development projects in the country. During the three and nine months ending September 30, 2014, the Company contributed $7.7 million and $28.6 million respectively to this foundation (2013: $9.7 million and $28.8 million) and advanced of $10.4 million to September 30, 2014 (December 31, 2013: $0.4 million). The Company's Executive Committee (comprised of Ronald Pantin, José Francisco Arata, Serafino Iacono and Miguel de la Campa) and an officer of the Company (Federico Restrepo) sit on the board of directors of the Pacific Rubiales Foundation.

i) As at September 30, 2014, the Company has demand loans receivable from Pacific Infrastructure in the amount of $71 million (December 31, 2013: Nil). The loans are guaranteed by Pacific Infrastructure's pipeline project and bear interest that ranges from LIBOR + 2% to 7% per annum. The Company owns 41.65% of Pacific Infrastructure. Ronald Pantin, José Francisco Arata, Serafino Iacono, Miguel de la Campa, Laureano von Siegmund and Federico Restrepo are on the board of directors of Pacific Infrastructure. Blue Pacific and certain other directors and officers of the Company collectively hold a minority interest in Pacific Infrastructure.

New Standards, Interpretations and Amendments Adopted by the Company

The accounting policies used in the preparation of the Interim Condensed Consolidated Financial Statements are consistent with those followed in the preparation of the Company's Annual Consolidated Financial Statements for the year that ended December 31, 2013, and the Interim Consolidated Financial Statements for the three months ending September 30, 2014.

Standards Issued but Not Yet Effective

IFRS 15 Revenue from Contracts with Customers

IFRS 15, "Revenue from Contracts with Customers" ("**IFRS 15**") was issued in May 2014 and will replace IAS 11, "Construction Contracts," IAS 18, "Revenue Recognition," IFRIC 13, "Customer Loyalty Programmes," IFRIC 15, "Agreements for the Construction of Real Estate," IFRIC 18, "Transfers of Assets from Customers," and SIC-31, "Revenue – Barter Transactions Involving Advertising Services." IFRS 15 provides a single, principle-based five-step model that will apply to all contracts with customers with limited exceptions, including, but not limited to, leases within the scope of IAS 17 and financial instruments and other contractual rights or obligations within the scope of IFRS 9 "Financial Instruments," IFRS 10, "Consolidated Financial Statements" and IFRS 11, "Joint Arrangements." In addition to the five-step model, the standard specifies how to account for the incremental costs of obtaining a contract and the costs directly related to fulfilling a contract. The standard's requirements will also apply to the recognition and measurement of gains and losses on the sale of some non-financial assets that are not an output of the entity's ordinary activities. IFRS 15 is required for annual periods beginning on or after January 1, 2017; earlier adoption is permitted. The Company is in the process of assessing the impact of IFRS 15 on its consolidated financial statements.

IFRS 9 (2014)

On July 24, 2014, the IASB issued the final version of IFRS 9 Financial Instruments ("**IFRS 9 (2014)"),** bringing together the classification and measurement, impairment and hedge accounting phases of the IASB's project to replace IAS 39 Financial Instruments: Recognition and Measurement and all previous versions of IFRS 9. The standard is effective for annual periods beginning on or after January 1, 2018, with early application permitted. Retrospective application will be required; however, transition reliefs are provided (including no restatement of comparative period information). The Company is in the process of assessing the impact of IFRS 9 (2014) on its consolidated financial statements.

9. Internal Controls over Financial Reporting

The Company's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of the Company's financial reporting for external purposes in accordance with IFRS. The Company's internal control over financial reporting includes:

- maintaining records that accurately and fairly reflect our transactions
- providing reasonable assurance that transactions are recorded as necessary for preparation of our consolidated financial statements in accordance with IFRS or other applicable, generally accepted accounting principles;
- providing reasonable assurance that receipts and expenditures are made in accordance with authorizations of management and the directors of the Company; and
- providing reasonable assurance that unauthorized acquisition, use or disposition of Company assets that could have a material effect on the Company's consolidated financial statements would be prevented or detected on a timely basis.

The Company's internal control over financial reporting may not prevent or detect all misstatements because of inherent limitations. Additionally, projections of any evaluation of effectiveness in future periods are subject to the risk that controls may become inadequate because of changes in conditions or deterioration in the degree of compliance with the Company's policies and procedures.

During the period ending September 30, 2014, there has been no change in the Company's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

10. Outlook

The Company continues to implement its financial and capital expenditure strategy through the fourth quarter of 2014, maintaining a healthy balance sheet and ensuring funding for future growth. For the first nine months of 2014, production averaged 148 Mboe/d, in-line with the low end of the Company's annual production guidance. This guidance was predicated on expected growth in the second half of the year. With the Rubiales Field performing below plan, impacted by limited water handling capacity, and weather related impacts on operations, we expect annual average production to be at the low end of our guidance, albeit still up approximately 15% over the prior year. Our previous guidance for 2014 was $2.5 billion in E&P expenditures – we now expect that this number will be closer to $2.3 billion, as we compensate for annual production at the low end of our guidance and lower world oil prices in the second half of 2014.

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 range from 5% to 23%, which the government allows companies to pay either in kind or in 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 first quarter of 2014, the Company fully delivered the remaining balance of prior period-accumulated PAP volumes.

Carrizales Field (Cravoviejo Block)

On April 27, 2013, the exploitation area of the Carrizales Field reached five million barrels of accumulated production of oil, activating the ANH rights on additional PAP 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.

PAP Disagreement with the ANH

Through various business acquisitions, the Company secured certain exploration contracts where there existed outstanding disagreements with the ANH 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. 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 which is 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 $150 million plus related interest of $70 million as of September 30, 2014. 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 plus + 4%, whereas the ANH has applied the highest legally authorized interest rate on Colombian peso liabilities, which is over 20%. The amount under discussion with the ANH for another contract is approximately $90 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 six to twelve months. 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 dispute resolution.

Update on Environmental Permits

Colombia

During the third quarter of 2014, the Company requested the following major environmental permits from the Environmental Authority in Colombia ("**ANLA**"):

- The Company requested the amendment of the Rubiales Environmental Licence in order to increase the water disposal to 500,000 bbl/d. This will allow the Company to increase the production of the field.
- The Company applied to the ANLA for the Global Environmental Licence to develop the Canaguaro Field. This licence includes the drilling of up to 80 production wells allowing the Company to develop the field to its commercial stage.
- The ANLA granted the permit needed to deliver production water to a third party in the Rubiales Field, and with this permit the Company can deliver treated water for agro industrial use.
- The ANLA initiated the licencing process for the Global Environmental Licence for the Copa and Rio Ariari Fields.

Peru

- For the 126 Block in the Ucayali Basin, the Company received the Environmental Impact Assessment ("**EIA**") allowing the Company to progress the discovery to an evaluation phase. This first EIA provides for 23 drilling pads, comprised of eight wells per pad plus 2D and 3D seismic programs. A second EIA, allowing for a long-term production test on the Sheshea-1X well is expected before year-end 2014.

12. Additional Financial Measures

This report contains the following financial terms that are not considered in IFRS: Adjusted EBITDA, Net Earnings from Operations, and Funds Flow 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) *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. Management believes that Adjusted EBITDA is an important indicator of the Company's ability to generate liquidity through operating cash flow to fund future working capital needs, service outstanding debt, and fund future capital expenditures. The exclusion of non-cash and one-time items eliminate the impact on the Company's liquidity and normalizes the result for comparative purposes. Other issuers may calculate Adjusted EBITDA differently.

A reconciliation of Net Earnings to Adjusted EBITDA follows:

	Three Months Ending September 30		Nine Months Ending September 30	
(in thousands of US$)	2014	2013	2014	2013
Net earnings	**$ 3,484**	**$ 84,013**	**$ 351,251**	**$ 285,670**
Adjustments to net earnings				
Income taxes expense	179,478	88,133	368,333	385,747
Foreign exchange loss (gain)	22,841	(767)	10,972	(9,203)
Finance cost	61,412	34,451	187,562	119,104
(Gain) loss on risk management contracts	(8,005)	6,143	(9,330)	12,331
(Gain) loss from equity investment	(284)	12,101	(15,687)	13,920
Other (income) expenses	(57,983)	14,817	(22,833)	35,377
Share-based compensation	27,180	5,184	30,271	41,121
Loss attributable to non-controlling interest	(324)	(1,720)	(1,355)	(7,224)
Depletion, depreciation and amortization	407,280	369,778	1,165,625	1,034,787
Adjusted EBITDA	**$ 635,079**	**$ 612,133**	**$ 2,064,809**	**$ 1,911,630**

b) *Net Earnings from Operations*

	Three Months Ending September 30		Nine Months Ending September 30	
(in thousands of US$)	2014	2013	2014	2013
Net earnings	**$ 3,484**	$ 84,013	**$ 351,251**	$ 285,670
Finance costs	61,412	34,451	187,562	119,104
Share of profit of equity-accounted investees	(284)	12,101	(15,687)	13,920
Foreign exchange loss (gain)	22,841	(767)	10,972	(9,203)
(Gain) loss on risk management	(8,005)	6,143	(9,330)	12,331
Other (income) expenses	(57,983)	14,817	(22,833)	35,377
Income tax expense	179,478	88,133	368,333	385,747
Loss attributable to non-controlling interest	(324)	(1,720)	(1,355)	(7,224)
Net earnings from operations	**$ 200,619**	$ 237,171	**$ 868,913**	$ 835,722

c) *Funds Flow from Operations*

(in thousands of US$)	Three Months Ending September 30 2014	Three Months Ending September 30 2013	Nine Months Ending September 30 2014	Nine Months Ending September 30 2013
Cash flow from operating activities	$ 599,067	$ 431,705	$ 1,494,640	$ 1,163,419
Changes in non-cash working capital	(7,147)	(23,395)	(116,832)	(272,842)
Funds flow from operations	**$ 606,214**	**$ 455,100**	**$ 1,611,472**	**$ 1,436,261**

13. Sustainability Policies

- As our company moves decisively towards incorporating shared value into the core of our strategy, we are proud to announce the EO100 certification in social, environmental, and economic practices, for our Rubiales and Quifa Fields. The EO100, which specifically involves a comprehensive voluntary system and a tool for social and environmental policies and their respective effectiveness, certifies production and exploration projects under a specific set of principles that align perfectly with our work here at PRE. The existence of this standard in the industry will accelerate the development of well-managed operations that implement systems, policies, and processes to reach and exceed industry norms and to align ourselves with the interests and priorities of our stakeholders. Pacific received EO's Bronze Leadership certification, because it met 100% of the Performance Target 1′s, and in certain areas exceeded to Performance Target 2 and 3. The certification is valid for three years pending an annual revision of goals to continue site improvement.

- Pacific was admitted into the Dow Jones Sustainability North America Index for the second year in a row, forming part of the select group of 149 companies that compose the North America division. The company´s recognition will continue to help investors realize the financial materiality of sustainability and is an excellent tool to measure the effectiveness of Pacific's sustainability strategy. At Pacific, we consider these issues of outmost importance for the continuity of the business and know that our permanence in these indexes will help us continue reaching responsible investors that share our same values. Pacific was also recognized as an industry leader by the Robeco Sam Sustainability yearbook.

- After evaluating our Sustainability practices and Corporate Social Responsibility framework and investments, Pacific Rubiales was awarded the recognition for Best Sustainable Oil & Gas Company in Latin America in 2014.

14. 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 operations 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.

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.

16. 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
API	American Petroleum Institute - gravity measure of petroleum liquid
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 metre
DWT	Dead weight tonnage
EPC	Engineering, procurement and construction
ESP	Electro-Submersible Pump
FOB	Free on board
GDP	Gross Domestic Product
ha	Hectare
km	Kilometres
KWh	Kilowatt Hour
Mbbl	Thousand barrels
Mbbl/d	Thousand barrels per day
Mboe	Thousand barrels of oil equivalent
Mboe/d	Thousand barrels of oil equivalent per day
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
MWh	Megawatts per hour
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