PACIFIC E&P

MANAGEMENT DISCUSSION & ANALYSIS

March 18, 2016
Year ended December 31, 2015

MESSAGE TO SHAREHOLDERS

The oil and gas industry has been profoundly altered as we are firmly entrenched in the second year of low international oil prices. The current pricing environment continues to threaten the economic health of the industry and indeed countries, with many E&P companies going into survival mode. Our immediate reaction in early 2015 to the lower oil price environment has allowed the Company to continue to deliver competitive operating results.

We were well positioned through 2015 with an active hedging program to protect cash flow and that is borne out in our operating results. We continue to focus on maintaining and gaining operational efficiencies and have again been able to drive cash operating costs to record lows. The Company has maintained its drive to reduce cash operating costs to record levels and continues to control G&A spending.

Our production increased slightly in 2015, where we achieved production from Colombia and Peru of 154,472 boe/d, including a marginal contribution from our latest addition of Block 192 in Peru. The Company has achieved its production guidance of 150,000 to 156,000 boe/d for 2015, representing modest growth over 2014.

We continue to focus our production portfolio on light and medium oil assets. Exploration discoveries that were made in 2014 and further delineated in 2015 in the Colombian foothills provided near-term production stability. The modest exploration activity in 2015 also identified a number of other light oil prospects similar to the discoveries already made with a potential inventory of development and delineation drilling locations.

During 2015, we earned revenues of $2,825 million and generated $1,031 million in Adjusted EBITDA and $579 million in funds flow from operations [(1)]. Despite the drop in oil prices, our operating netback for the year ended December 31, 2015 was $25.55/boe, benefitting from reduction of total costs and the strong hedging position which generated superior realized prices.

We continued to streamline our operations and generated further cost reductions during the fourth quarter of 2015 to record low cash operating costs. The Company achieved underlying operating costs of $18.64/boe and total operating costs (including overlift and other costs) of $22.52/boe, compared with $26.44/boe and $27.28/boe, respectively, for the fourth quarter of 2014. Further cost savings and G&A reductions are still possible through 2016, due to additional restructuring of work processes.

The Company developed a very workable strategy in late 2014 to address the collapse in oil prices – cash operating costs and G&A were cut, and capital expenditures were slashed to only priority projects that allowed us to maintain production and protect the value of the asset base. However, the further collapse of oil prices in early 2016 caused us to engage in a process to restructure the balance sheet.

As announced in January 2016, we invoked a 30-day grace period for making interest payments on two series of our outstanding notes to engage advisors and assess strategic alternatives to make the Company's capital structure more suitable to current market conditions. Subsequent to that announcement, we have entered into forbearance agreements with certain noteholders and banks until March 31, 2016, to allow the Company time to work with the Independent Committee of the Board of Directors, the Company's advisors, the banks and noteholders to come to a consensual and comprehensive restructuring of the Company's balance sheet.

In summary, we believe strongly in the Company's assets and we are working diligently to ensure that the value of these assets is preserved for enhancement in the future. These have become exceptionally difficult times globally for the oil industry, but we believe that the Company can weather the storm and continue to move forward with a judicious use of our resources and efficient use of our technical and operational expertise. We are prepared for the long-term as well as for the opportunities before us and any challenges that may emerge.

Ronald Pantin
Chief Executive Officer
March 18, 2016

(1) The terms Adjusted EBITDA and funds flow from operations are non-IFRS measures. These non-IFRS measures do not have any standardized meanings and therefore are unlikely to be comparable to similar measures presented by other companies. These non-IFRS measures are included because the Company's 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. See "Additional Financial Measures" on page 39.

CONTENTS

Legal Notice – Forward-Looking Information and Statements

Certain statements in this Management, Discussion and Analysis ("**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," or "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, 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 such expectations will prove to be correct, and thus such 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 heading "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 increase costs for the Company, and so 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 oil and gas that will be encountered if the property in question 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. Disclosure of well test results may be preliminary until analyzed or interpreted, and are not necessarily indicative of long-term performance or ulitmate recovery.

For more information, please see the Company's Annual Information Form, dated March 18, 2016, 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 Audited Annual Consolidated Financial Statements and related notes for the years ending December 31, 2015 and 2014. The preparation of financial information is reported in United States dollars and is in accordance with International Financial Reporting Standards ("**IFRS**") as issued by the International Accounting Standards Board ("**IASB**"), unless otherwise noted. All comparative percentages are between the years ending December 31, 2015 and 2014, unless otherwise noted.

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

Additional information with respect to the Company, including the Company's quarterly and annual financial statements and the Annual Information Form, has been filed with Canadian securities regulatory authorities and is available on SEDAR at www.sedar.com, on SIMEV at www.superfinanciera.gov.co/web_valores/Simev, and on the Company's website at www.pacific.energy. 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. In the case of differences or discrepancies between the original and the translated version, the English document shall prevail and be treated as the governing version.

1 Highlights for the Year and Quarter Ended December 31, 2015

Financial and Operating Summary

(in thousands of US$ except per share amounts or as noted)	Year Ended December 31		Three Months Ended December 31	
	2015	**2014**	**2015**	**2014**
Operating Activities				
Average sales volumes (boe/d)	**159,113**	158,026	**171,928**	161,445
Average oil and gas sales (boe/d)	**151,806**	145,941	**171,039**	147,208
Average trading sales (bbl/d)	**7,307**	12,085	**889**	14,237
Average net production (boe/d)	**154,472**	147,423	**159,831**	147,075
Average net production oil (bbl/d)	**145,245**	137,076	**149,368**	137,019
Average net production gas (boe/d)	**9,227**	10,347	**10,463**	10,056
Combined price ($/boe)	**48.51**	85.35	**41.22**	65.64
Combined netback ($/boe)	**25.55**	54.84	**18.70**	38.36
Combined operating cost ($/boe)	**22.96**	30.51	**22.52**	27.28
Capital expenditures	**725,512**	2,382,296	**160,154**	757,842
Financials				
Total oil and gas sales ($)	**$ 2,824,546**	$ 4,950,022	**$ 651,970**	$ 991,508
Adjusted EBITDA [1]	**1,031,324**	2,484,085	**182,917**	419,276
Adjusted EBITDA margin (Adjusted EBITDA/Revenues)	**37%**	50%	**28%**	42%
Per share - basic ($) [2]	**3.29**	7.87	**0.58**	1.33
Funds flow from operations [1]	**578,500**	2,021,241	**42,277**	409,769
Funds flow from operations margin (Funds flow from operations/Revenues)	**20%**	41%	**6%**	41%
Per share - basic ($) [2]	**1.85**	6.41	**0.13**	1.30
Net (loss) earnings from operations before impairment and exploration expenses	**(503,823)**	832,265	**(198,814)**	(36,648)
Net loss [3]	**(5,461,859)**	(1,309,625)	**(3,895,908)**	(1,660,876)
Per share - basic ($) [2]	**(17.34)**	(4.15)	**(12.37)**	(5.26)

1. See "Additional Financial Measures" on page 39.
2. The basic weighted average numbers of common shares for the year ended December 31, 2015 and 2014 were 315,021,198 and 315,487,230 respectively.
3. Net loss attributable to equity holders of the parent.

Breakdown of Oil & Gas and Trading Results

	Year Ended December 31					
	2015			2014		
	Oil & Gas	Trading	Total	Oil & Gas	Trading	Total
Volume sold (boe/d)	**151,806**	**7,307**	**159,113**	**145,941**	**12,085**	**158,026**
Average realized price ($/boe)	**48.51**	**51.16**	**48.64**	**85.35**	**91.51**	**85.82**
Financial Results (in thousands of US$)						
Revenues	**2,688,087**	**136,459**	**2,824,546**	**4,546,359**	**403,663**	**4,950,022**
Cost of operations	**1,272,148**	**128,948**	**1,401,096**	**1,625,840**	**400,674**	**2,026,514**
Production and purchase cost of barrels sold	434,879	128,948	563,827	805,397	400,674	1,206,071
Transportation cost (trucking and pipeline) (1)	600,573	-	600,573	690,060	-	690,060
Diluent cost	113,141	-	113,141	115,121	-	115,121
Other costs (Royalties paid in cash)	88,110	-	88,110	77,978	-	77,978
Overlift/Underlift	35,445	-	35,445	(62,716)	-	(62,716)
Gross margin	**1,415,939**	**7,511**	**1,423,450**	**2,920,519**	**2,989**	**2,923,508**

	Three Months Ended December 31					
	2015			2014		
	Oil & Gas	Trading	Total	Oil & Gas	Trading	Total
Volume sold (boe/d)	**171,039**	**889**	**171,928**	**147,208**	**14,237**	**161,445**
Average realized price ($/boe)	**41.22**	**40.89**	**41.22**	**65.64**	**78.32**	**66.75**
Financial Results (in thousands of US$)						
Revenues	**648,626**	**3,344**	**651,970**	**888,930**	**102,578**	**991,508**
Cost of operations	**354,403**	**2,525**	**356,928**	**369,515**	**101,263**	**470,778**
Production and purchase cost of barrels sold	122,614	2,525	125,139	185,675	101,263	286,938
Transportation cost (trucking and pipeline) (1)	137,291	-	137,291	147,885	-	147,885
Diluent cost	33,345	-	33,345	24,540	-	24,540
Other costs (Royalties paid in cash)	25,829	-	25,829	11,802	-	11,802
Overlift/Underlift	35,324	-	35,324	(387)	-	(387)
Gross margin	**294,223**	**819**	**295,042**	**519,415**	**1,315**	**520,730**

1. For the year and quarter ended December 31, 2015, transportation costs on a boe basis includes the Company's share of the income from equity investments in the ODL and Bicentenario pipelines which were $54.5 million and $15.6 million, respectively. Refer to Note 19 of the Audited Annual Consolidated Financial Statements for additional details.

Highlights

Operational

- During the year 2015, the Company maintained strong average daily net production after royalties of 154,472 boe/d, a 5% increase compared with 147,423 boe/d for 2014, and within the Company's guidance for the year of 150,000-156,000 boe/d. In the fourth quarter of 2015, average daily net production after royalties increased to 159,831 boe/d, higher by 9% as compared to the same period of 2014.
- During 2015, the Company continued to streamline its operations to generate further cost reductions. The Company achieved a record underlying combined operating cost of $20.73/boe, and a total combined operating cost (including overlift and other costs) of $22.96/boe, compared with $30.23/boe and $30.51/boe, respectively, in 2014. In the fourth quarter of 2015, total combined operating cost was $22.52/boe, compared with $27.28/boe for the same period in 2014.

- In 2015, the Company was able to maintain stable production levels in the Rubiales field despite the anticipated depletion. The Company continued to optimize wells and facilities to maximize production, while minimizing capital expenditures and only drilling the minimum number of wells. Rubiales field production comprised 35% of the net production for the year ended December 31, 2015. Into 2016, production from the Rubiales field has slightly declined as projected, and plans are on schedule to return the field to Ecopetrol in June 2016.

Financial

- Revenue decreased to $2,825 million compared to $4,950 million in 2014, reflecting the nearly 45% year-on-year decline in realized crude oil prices. Revenue for the fourth quarter of 2015 decreased to $652 million compared with $992 million for the same period in 2014, also due to lower realized prices, but partially offset by higher volumes sold in the period.
- In 2015, revenue included $290 million in realized gains from oil hedging contracts entered into in 2014 and early 2015, helping to support the Company's realized prices above market rates during the year. Average oil and gas sales (including trading) for the year were 159,113 boe/d, 1% higher than 158,026 boe/d in 2014. In February 2016, the Company terminated its outstanding hedging positions early, taking advantage of the recent positive mark-to-market movement to improve our liquidity.
- Combined netbacks continued to be strong despite the reduction in oil prices. Combined operating netback on oil and gas for the year was $25.55/boe, 53% lower than the $54.84/boe in 2014. The decrease was mainly attributable to the decline in market prices for crude oil, partially offset by the reduction in combined operating costs achieved during the year and the strong hedging position which generated superior realized prices. The Company's average sales price per barrel of crude oil and natural gas was $48.51/boe for the year and $41.22/boe for the fourth quarter of 2015, down from $85.35/boe and $65.64/boe, respectively, a year ago.
- Adjusted EBITDA for the year was $1,031 million, and Funds flow was $579 million. Adjusted EBITDA and Funds flow were 58% and 71% lower, respectively, compared with the year 2014.
- G&A expenses decreased to $221 million in 2015 from $361 million in 2014, as the Company continues to maintain its drive to control G&A and all non-essential spending and activities in light of the precipitous decrease in oil prices.
- Net loss for the year was $5,462 million, largely due to the $4,907 million non-cash impairment charge taken mainly on oil and gas assets and exploration expenses, reflecting the significant decline in crude oil prices. It is important to highlight that this impairment is aligned with International Financial Reporting Standards ("**IFRS**") accounting rules and may be reversed, in whole or in part, once market conditions improve with a better oil price trend.
- Total capital expenditures decreased to $726 million in 2015, compared with $2,382 million in 2014. Capital expenditures will continue to approximately match cash flow, with spending mainly focused on high-impact and low-risk development work.

Proved plus Probable reserves ("2P")

- Total certified 2P net after royalties reserves were 290.8 MMboe as at December 31, 2015, 43% lower compared with 510.9 MMboe as at December 31, 2014. Proved reserves (1P) were 197.8 MMboe as at December 31, 2015 compared with 315.0 MMboe as at December 31, 2014.
- The decrease in 2P reserves was primarily attributable to the significantly lower oil price forecasts resulting in economic revisions plus the impact of normal course technical revisions as assessed by the Company's independent reserves evaluators. Economic revisions as a result of lower oil prices can usually be reversed with higher oil prices, which would result in positive economic revisions in the future. Additional information relating to 2015 reserves is provided in the Company's Annual Report on Reserve Data F-51-101, dated March 18, 2016.

Exploration

- Exploration activity during 2015 was primarily focused on the Central and Deep Llanos in Colombia and added an average of 14,591 bbl/d of light oil production in 2015. Fifteen exploration wells (including 11 appraisal wells) were drilled resulting in 13 discoveries and the confirmation of ten other previous discoveries for a 87% success rate.
- In the Santos Basin in Brazil four successful wells (including sidetrack well bores) were drilled by Karoon Petroleo e Gas Ltda. ("**KPGL**"), the block operator. Three of the successful wells were appraising a previous discovery in the Kangaroo structure with a new exploration discovery Echidna 1.
- In Block 131, Ucayali Basin, Perú, the Los Angeles Noi 3X and Los Angeles 2CD appraisal wells were drilled, confirming the extension of the Los Angeles reservoir to the north and south of the prospect, respectively.

Balance Sheet Management

- On December 28, 2015, the Company obtained waivers for the debt leverage and net equity covenants under its $1 billion Revolving Credit Facility and the Bank of America, HSBC, and Bladex credit facilities.
- On January 14, 2016, the Company announced it had elected to utilize the 30-day grace period under the applicable note indentures and not make interest payments of $66.2 million in the aggregate on its senior notes maturing in 2019 (2019 Senior Notes) and those maturing in 2025 (2025 Senior Notes, and together with the 2019 Senior Notes, the "**Notes**") as they became due on January 26, 2016 and January 19, 2016, respectively. The failure to pay such interest constituted an event of default under the applicable note indentures on February 25, 2016 in respect of the 2019 Senior Notes and on February 18, 2016 in respect of the 2025 Senior Notes. On February 18, 2016, the Company entered into an extension agreement (the "**Noteholder Extension Agreement**") with certain holders of the 2019 Senior Notes and 2025 Senior Notes. Under the terms of the Noteholder Extension Agreement, holders of approximately 34% of the aggregate principal amount of outstanding 2019 Senior Notes and 42% of the aggregate principal amount of outstanding 2025 Senior Notes have agreed, subject to certain terms and conditions, to forbear from declaring the principal amounts of the Notes (and certain additional amounts) due and payable as a result of certain specified defaults until March 31, 2016.
- On February 19, 2016, the Company entered into separate forbearance agreements (the "**Lender Forbearance Agreements**") in respect of the Revolving Credit Facility and the Bank of America, Bladex, and HSBC credit facilities. Under the terms of the Lender Forbearance Agreements, the requisite lenders under these credit facilities have also agreed, subject to certain terms and conditions, to forbear from declaring the principal amounts of such credit facilities due and payable as a result of certain specified defaults until March 31, 2016.
- The Company continues to work with its debtholders to formulate a comprehensive capital restructuring plan to address the current oil price environment and ensure the long-term viability of its business. The Company remains, and intends to remain, current with its suppliers, trade partners and contractors. Normal operations continue in Colombia and the other jurisdictions within which the Company operates.

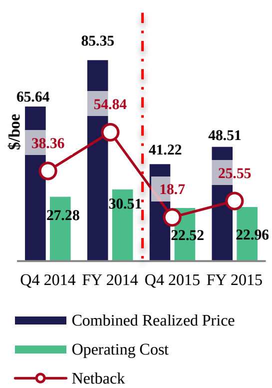
Going Concern Uncertainty

- Despite a number of cost reduction initiatives that have been implemented by the Company, at current oil prices the Company will likely need new financing to fund its interest payments and debt repayments as they come due, and possibly operating cash needs. As mentioned above, the Company currently has in place certain forbearance agreements with certain holders of its senior notes and revolving and bank credits facilities that remain in effect until March 31, 2016. The Company has also breached several minimum credit rating covenants in certain operational agreements it has entered into, as a result of downgrades of the Company's credit rating during 2015, although waivers relating to these covenants have been granted for various limited periods. There can be no certainty as to the ability of the Company to successfully restructure its long-term debts, amend the applicable operating agreements to eliminate the credit rating covenants, and obtain new financing should low crude prices persist, and accordingly, there is a material uncertainty that may cast doubt on the Company's ability to continue as a going concern. Refer to Note 2 to the Annual Audited Consolidated Financial Statememts.

2 Operating Netbacks

Our operating costs continued decreasing in 2015 as a result of strategies for streamlining production costs and optimizing field operations, and the depreciation of the Colombian peso against the U.S. dollar.

COMBINED OPERATING NETBACK



Oil & Gas Operating Netback

Combined operating netbacks for the years ended December 31, 2015 and December 31, 2014 are summarized below:

	Year Ended December 31					
	2015			2014		
	Crude Oil	Natural Gas	Combined	Crude Oil	Natural Gas	Combined
Average daily volume sold (boe/day)[(1)]	**142,595**	**9,211**	**151,806**	**135,622**	**10,319**	**145,941**
Operating netback ($/boe)						
Crude oil and natural gas sales price	49.56	32.28	48.51	89.46	31.27	85.35
Production cost of barrels sold [(2)]	8.19	2.54	7.85	15.98	3.86	15.12
Transportation (trucking and pipeline) [(3)]	11.51	0.42	10.84	13.93	0.07	12.95
Diluent cost	2.17	-	2.04	2.33	-	2.16
Total operating cost	**21.87**	**2.96**	**20.73**	**32.24**	**3.93**	**30.23**
Other costs [(4)]	0.97	-	0.91	0.44	0.04	0.41
Royalties paid in cash	0.59	2.02	0.68	0.98	2.00	1.05
Overlift/Underlift [(5)]	0.68	0.07	0.64	(1.26)	(0.03)	(1.18)
Total operating cost including overlift/underlift, royalties paid in cash and other costs	**24.11**	**5.05**	**22.96**	**32.40**	**5.94**	**30.51**
Operating netback crude oil and gas ($/boe)	**25.45**	**27.23**	**25.55**	**57.06**	**25.33**	**54.84**

1. Combined operating netback data is based on the weighted average of daily volume sold, which includes diluents necessary for the blending of 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 delivery points for customers. For the year and fourth quarter ended 2015, transportation cost included the Company's share of the income from equity investments in the ODL and Bicentenario pipelines.
4. Other costs mainly correspond to inventory fluctuation, storage cost, the net effect of the currency hedges of operating expenses incurred in Colombian pesos during the period, and external road maintenance at the fields.
5. Corresponds to the net effect of the overlift position of $35 million in expenses during 2015 ($63 million in income for the year 2014).

In 2015, the Company's average combined realized price decreased to $48.51/boe from $85.35/boe in 2014, in line with the global oil prices trend. The realized oil price decreased to $49.56/bbl from an average of $89.46/bbl in 2014.

The Company adapted to the low oil price environment and continued to streamline operations to generate further cost reductions in 2016. Total combined operating costs decreased from $30.51/boe in 2014 to an average of $22.96/boe in 2015. Combined operating costs, including production, transportation, and dilution costs, decreased to $20.73/boe for 2015 from $30.23/boe for 2014. The decreased unit cost is mainly a result of the continued operating cost optimization, and a 32% depreciation of the Colombian peso against the U.S. dollar. During 2015, there was a disruption of the Bicentenario Pipeline of 204.5 days. However, the Company was able to source available operational capacity in the OCENSA pipeline at comparable per unit costs.

Netbacks continue to be strong despite the drop in crude oil prices. For the year ended 2015, the combined crude oil and gas operating netback was $25.55/boe compared with $54.84/boe for the year 2014. The crude oil operating netback was $25.45/bbl, 55% lower compared to 2014 of $57.06/bbl.

Combined operating netbacks for the three months ended on December 31, 2015 and 2014 are summarized below:

	Three Months Ended December 31					
	2015			2014		
	Crude Oil	Natural Gas	Combined	Crude Oil	Natural Gas	Combined
Average daily volume sold (boe/day)[1]	**160,498**	**10,541**	**171,039**	**137,083**	**10,125**	**147,208**
Operating netback ($/boe)						
Crude oil and natural gas sales price	41.86	31.43	41.22	68.27	29.97	65.64
Production cost of barrels sold [2]	8.12	2.74	7.79	14.40	4.42	13.71
Transportation (trucking and pipeline) [3]	9.30	-	8.73	11.70	0.33	10.92
Diluent cost	2.26	-	2.12	1.95	-	1.81
Total operating cost	**19.68**	**2.74**	**18.64**	**28.05**	**4.75**	**26.44**
Other costs [4]	1.11	-	1.04	0.16	0.09	0.16
Royalties paid in cash	0.49	2.35	0.60	0.64	1.66	0.71
Overlift/Underlift [5]	2.37	0.33	2.24	(0.03)	0.04	(0.03)
Total operating cost including overlift/underlift, royalties paid in cash and other costs	**23.65**	**5.42**	**22.52**	**28.82**	**6.54**	**27.28**
Operating netback crude oil and gas ($/boe)	**18.21**	**26.01**	**18.70**	**39.45**	**23.43**	**38.36**

Notes: Refer to the operating netback table on page 5.

For the fourth quarter of 2015, the combined crude oil and gas operating netback was $18.70/boe, $19.66/boe lower than the same period of 2014 ($38.36/boe). The crude oil operating netback was $18.21/bbl, $21.24/bbl lower than the same period of 2014 ($39.45/bbl). The lower netback was mainly attributable to the decline in crude oil prices, which also resulted in the lower realized price of $41.22/boe on a combined basis for the three months ended December 31, 2015, compared with $65.64/boe in the same period of 2014. At the same time, the Company achieved a significant reduction in total operating costs (including over/under lifts and other costs) of $4.76/boe to $22.52/boe. Reductions in field costs were achieved through a number of initiatives including streamlining the workforce and a 32% depreciation of the Colombian Peso against the U.S. dollar.

Trading Netback

Crude oil trading	Year Ended December 31		Three Months Ended December 31	
	2015	2014	2015	2014
Average daily volume sold (bbl/d)	**7,307**	**12,085**	**889**	**14,237**
Operating netback ($/bbl)				
Crude oil traded sales price	51.16	91.51	40.89	78.32
Cost of purchases of crude oil traded	48.35	90.84	30.87	77.31
Operating netback crude oil trading ($/bbl)	**2.81**	**0.67**	**10.02**	**1.01**

In 2015, the Company traded an average of 7,307 bbl/d as compared with 12,085 bbl/d in 2014. However, the average netback for volumes traded in 2015 was $2.81/bbl, a gross margin of $7.51 million; versus the netback captured in 2014 of $0.67/bbl, a gross margin of $2.99 million. A similar trend of improved netbacks was observed during the fourth quarter of 2015.

The nature of our oil for trading business is opportunistic and often depends on the available capacity under our pipeline transportation agreements. Our ability to acquire crude oil for trading purposes allows the Company to utilize any available capacity and offset the take-or-pay transport fees. The drop in the volumes sold in 2015 was mainly attributable to the reduction in oil production in Colombia, which increased the available capacity in the pipelines for other traders to compete with better conditions.

3 Operational Results

Production and Development Review

Production remained stable in 2015 in Colombia and Peru including a marginal contribution from the latest addition of Block 192 in Peru. Despite the depletion in production levels at the Rubiales field as previously expected, production was within the Company's guidance of 150 to 156 Mboe/d for 2015, representing modest growth over 2014.

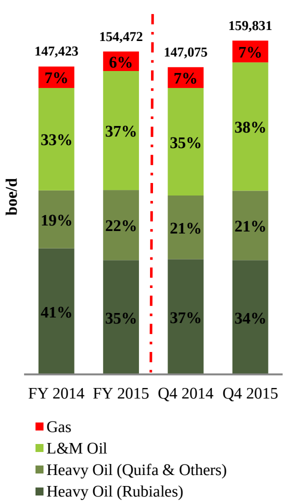
During 2015, net production after royalties and internal consumption totaled 154,472 boe/d, representing an increase of 7,049 boe/d (4.8%) from the average net production of 147,423 boe/d reported in the previous year. Average net production for the fourth quarter of 2015 reached 159,831 boe/d, 9% higher than the 147,075 boe/d for the same quarter of 2014.

We have significantly increased our light and medium oil production through targeted acquisitions and exploration discoveries.

We have significantly increased our light and medium oil production through targeted acquisitions and exploration discoveries. During 2015, light and medium net oil production totaled 57,022 bbl/d, increasing 16% in comparison to 2014. Part of the increase corresponds to production from Block 192 in Peru, which became part of the Company on August 30, 2015. Heavy oil production from the Quifa and other fields also increased by 21% during 2015 compared with 2014. Light and medium oil and heavy crude oil production (excluding the Rubiales field) now represents 37% and 22%, respectively, of total net oil and gas production, while production from the Rubiales field represented 35% of the total net production, down from 41% in 2014.

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

NET PRODUCTION AFTER ROYALTIES



Full Year 2015 Production

	Average Year Production (in boe/d)					
	Total field production		Gross share before royalties [1]		Net share after royalties	
Producing fields - Colombia	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**
Rubiales / Piriri	163,659	180,519	68,392	75,460	54,713	60,368
Quifa SW [2]	56,197	56,573	33,380	33,607	29,643	23,685
	219,856	**237,092**	**101,772**	**109,067**	**84,356**	**84,053**
Other fields in Colombia						
Light and medium [3]	57,290	54,521	55,067	49,907	51,436	46,341
Gas [4]	10,312	11,372	9,227	10,347	9,227	10,347
Heavy oil [5]	5,880	6,312	4,047	4,273	3,867	4,041
	73,482	**72,205**	**68,341**	**64,527**	**64,530**	**60,729**
Total production Colombia	**293,338**	**309,297**	**170,113**	**173,594**	**148,886**	**144,782**
Producing fields in Peru						
Light and medium [6]	10,544	5,650	5,586	2,641	5,586	2,641
	10,544	**5,650**	**5,586**	**2,641**	**5,586**	**2,641**
Total production Colombia and Peru	**303,882**	**314,947**	**175,699**	**176,235**	**154,472**	**147,423**

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 with a high-price clause (PAP) 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, which produced at 3,626 bbl/d and was acquired from LAEFM Colombia Ltda. ("**LAEFM**") effective April 1, 2014, pursuant to a transaction that closed on August 12, 2014.
4. Includes La Creciente, Dindal / Rio Seco, Cerrito, Carbonera, and Guama fields.
5. Includes Cajua, Sabanero, CPE-6, Rio Ariari, Prospecto S, and Prospecto D fields.
6. Includes 691 bbl/d of net production, with respect to the receivable outstanding from BPZ Exploración y Producción S.R.L. ("**BPZ**"). Also includes Block 192, which has been operating since August 30, 2015 with 12,000 bbl/d of gross production under normal conditions.

Fourth Quarter 2015 Production

	Average Quarter Production (in boe/d)					
	Total field production		Gross share before royalties [1]		Net share after royalties	
Producing fields - Colombia	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**
Rubiales / Piriri	164,056	166,052	68,392	68,864	54,713	55,091
Quifa SW [2]	55,629	60,209	33,042	35,724	29,818	26,079
	219,685	**226,261**	**101,434**	**104,588**	**84,531**	**81,170**
Other fields in Colombia						
Light and medium [3]	53,544	55,132	53,731	51,783	50,959	48,120
Gas [4]	11,924	11,304	10,463	10,056	10,463	10,056
Heavy oil [5]	5,227	6,872	3,575	4,655	3,416	4,441
	70,695	**73,308**	**67,769**	**66,494**	**64,838**	**62,617**
Total production Colombia	**290,380**	**299,569**	**169,203**	**171,082**	**149,369**	**143,787**
Producing fields in Peru						
Light and medium [6]	18,279	7,493	10,462	3,288	10,462	3,288
	18,279	**7,493**	**10,462**	**3,288**	**10,462**	**3,288**
Total production Colombia and Peru	**308,659**	**307,062**	**179,665**	**174,370**	**159,831**	**147,075**

Notes: Refer to Full Year 2015 production table on page 7.

Colombia

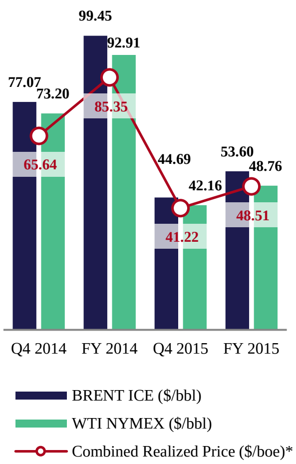
The Company continues to optimize wells and facilities to maximize production while minimizing capital expenditures. Net production after royalties in Colombia increased to 148,886 boe/d (293,338 boe/d total field production) for the year ended December 31, 2015, from 144,782 boe/d (309,297 boe/d total field production) in the same period of 2014. During the fourth quarter of 2015, the average net production after royalties in Colombia rose to 149,369 boe/d (290,380 boe/d total field production), 4% higher than 143,787 boe/d (299,569 boe/d total field production) during the fourth quarter of 2014.

Production growth was offset by a 9% decrease in net production at the Rubiales field year-over-year. Production reductions at the mature Rubiales field were primarily due to restricted water disposal capacity as a result of delays in the environmental approval for the Agrocascada water irrigation project. Plans are on schedule to return the field to Ecopetrol in June 2016.

Peru

Production from Peru corresponds to the 49% participating interest in Block Z-1, the 30% working interest in the Los Angeles discovery in Block 131, and the Block 192 operation contract. Net production after royalties for the fourth quarter of 2015 in Peru was 10,462 bbl/d, with increases in comparison with the same period of 2014, mainly from additional net production in Block 192 of 7,818 bbl/d.

PRICES



** Excluding Trading*

Sales, Trading, and Pricing

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

	Average Volume of Sales and Prices			
	Year Ended December 31		Three Months Ended December 31	
Colombia and Peru	**2015**	**2014**	**2015**	**2014**
Oil (bbl/d)	144,985	136,324	161,918	139,247
Gas (boe/d)	9,211	10,319	10,541	10,125
Trading (bbl/d)	7,307	12,085	889	14,237
Total barrels sold (boe/d)	161,503	158,728	173,348	163,609
Sales from E&E assets (boe/d) [(1)]	(2,390)	(702)	(1,420)	(2,164)
Net barrels sold (in boe/d)	159,113	158,026	171,928	161,445
Realized Prices				
Oil realized price ($/bbl)	49.56	89.46	41.86	68.27
Gas realized price ($/boe)	32.28	31.27	31.43	29.97
Combined realized price oil and gas $/boe (excluding trading)	48.51	85.35	41.22	65.64
Trading realized price ($/bbl)	51.16	91.51	40.89	78.32
Reference Market Prices				
WTI NYMEX ($/bbl)	48.76	92.91	42.16	73.20
ICE BRENT ($/bbl)	53.60	99.45	44.69	77.07
Guajira Gas Price ($/MMBtu) [(2)]	5.17	5.65	5.44	5.67
Henry Hub average Natural Gas Price ($/MMBtu)	2.63	4.26	2.23	3.83

1. Includes sales from exploration and evaluation assets.
2.The domestic natural gas sales price is referenced as the Market Reference Price (“**MRP**”) for gas produced at La Guajira field. Reference: Official circulars 002 and 090 of 2014, the Energy and Gas Regulatory Commission (“**CREG**”), and bulletin 060 of 2015, Market Operator of Natural Gas.

The crude oil and gas combined realized price for the year ended 2015 was $48.51/boe, including a realized hedging gain of $5.23/boe, which helped to support the Company’s realized prices above market rates during the year.

During 2015, average oil and gas sales (including trading) totalled 159,113 boe/d, which represented an increase of 1% in comparison with 158,026 boe/d in 2014. Oil and gas sales for the fourth quarter of 2015 reached 171,928 boe/d, representing a 6% increase from the volumes reported in the fourth quarter of 2014 of 161,445 boe/d.

The crude oil and gas combined realized price for the year ended December 31, 2015, reached $48.51/boe, $36.84/boe lower as compared with the same period of 2014. The combined realized price of $48.51/boe includes a realized oil price-hedging gain of $5.23/boe, which helped support the Company’s realized prices above market rates during the year. See additional details under the “Oil Price-Hedging” section on page 21.

In 2015, the WTI NYMEX price decreased by $44.15/bbl (47.5%) to an average of $48.76/bbl, compared with the average of $92.91/bbl in 2014. Likewise, the ICE BRENT price declined by $45.85/bbl (46.1%) to an average of $53.60/bbl, compared with the average of $99.45/bbl in 2014.

During the fourth quarter of 2015, the WTI NYMEX price decreased by $4.34/bbl (9.3%) to $42.16/bbl from $46.50/bbl in the third quarter of 2015. Similarly in the fourth quarter of 2015, the ICE BRENT price decreased by $6.61/bbl (12.9%) to $44.69/bbl from $51.30/bbl in the third quarter of 2015.

Exploration Review and Update

Exploration activity during 2015 was primarily focused on the Central and Deep Llanos in Colombia, and added an average of 14,591 bbl/d of light oil production in 2015.

During the year ended 2015, the Company drilled or was a partner in fifteen exploration and appraisal wells in Colombia, Brazil, Peru, and Papua New Guinea, resulting in three discoveries and the confirmation of ten other previous discoveries for a total of 13 discoveries or a 87% success rate. During the fourth quarter of 2015 no drilling activity was performed.

	Year Ended December 31	
	2015	**2014**
Successful exploration wells	5	15
Successful appraisal wells (1)	8	24
Successful stratigraphic wells	-	4
Dry wells	2	13
Total	**15**	**56**
Success rate	**87%**	**77%**

1. Includes horizontal appraisal well.

Exploration Activities 2015

Brazil

The operator of the blocks, Karoon Petróleo e Gas Ltda. ("**KPGL**"), completed operations on the Kangaroo-2 (K-2) appraisal well located on Block S-M-1165, offshore Santos Basin, Brazil, including the main wellbore plus two sidetrack wellbores. Flow testing and wireline fluid samples obtained from the three penetrations of the Kangaroo 2 well, in combination with the results of Kangaroo-1, will provide important technical data to assess the commerciality and update a potential field development plan for the discovery.

KPGL spudded the Kangaroo West-1 (KW-1) exploration well, the second commitment well. Also located on Block S-M-1165, KW-1 was drilled to a total depth of 10,397 feet MD (10,307 feet TVDSS). The well failed to intersect hydrocarbons and was plugged and abandoned as a dry hole.

In the Santos Basin in Brazil four successful exploration wells (including sidetrack well bores) were drilled by Karoon. Echidna-1 Well confirmed the presence of hydrocarbon accumulations in the salt-flank structure known as the Echidna Prospect. A production flow test (DST) of two Paleocene reservoir intervals was conducted in May. The flow test was for 27 hours and produced a facility-constrained stabilized flow rate of 4,650 bbl/d from the Paleocene reservoir intervals with a flowing well-head pressure of 504 psi on a 1" choke. Oil samples recovered during the test were measured at 38.6° API oil with a gas-oil ratio of 701 scf/stb. The positive Echidna-1 DST production test confirmed the Echidna discovery and confirmed that the quality of Paleocene reservoir in Echidna is better than observed anywhere else in the Santos acreage.

Peru

During 2015, two successful appraisal wells were drilled in the Los Angeles 1X discovery, Los Angeles Noi 3X and Los Angeles 2CD. Long term testing of the Los Angeles field has continued during 2015 and over 1,437 Mbbl of 45° API oil has been produced in total. Los Angeles 1X, Los Angeles Noi 3X and Los Angeles 2CD have produced over 940 Mbbl, 406 Mbbl, and 91 Mbbl of oil respectively.

Colombia

Guatiquía Block: 100% Interest

Long term testing of the Avispa, Ceibo and Ardilla fields continued throughout 2015. Over 5,861 Mbbl of 17-22° API oil has been produced in total. Avispa, Ceibo and Ardilla fields have produced over 3,321 Mbbl, 2,135 Mbbl and 405 Mbbl of oil respectively.

In 2015, six appraisal wells were drilled in these pools including Avispa 2, 3, 4, 6 and 7ST and Ceibo 2.

Corcel Block 100% Interest

Long term testing of the Espadarte and Zural discoveries continued throughout 2015. Espadarte and Zural have produced over 699 Mbbl and 51 Mbbl of oil respectively.

Update on Exploration during the Fourth Quarter of 2015

Peru

Block 131: 30% Interest

The application for commerciality in Los Angeles Pool was approved by Perupetro on December 23, 2015. The production contract will expire on January 18, 2038. Long-term testing of the Los Angeles field has continued through the fourth quarter of 2015 with a cumulative production of over 1,431 Mbbl of 45° API oil from Los Angeles 1X, Los Angeles Noi 3X, and Los Angeles 2CD wells, which have produced over 940 Mbbl, 406 Mbbl, and 85 Mbbl of oil, respectively.

Colombia

Guatiquía Block: 100% Interest

The Avispa-4 well was spudded on October 15, 2015, and reached a depth of 12,480 feet MD on November 3, 2015. The log analysis indicates 38.5 feet of net potential pay in the Lower Sand 1 formation, and 18.5 feet of net potential pay in the Upper Guadalupe Formation. The well was completed in a 6 feet interval in the Lower Sand 1A, and from November 28 to December 31, 2015, recovered 98 Mbbl of 19.3 API oil. The well has produced an average of 2,171 bbl/d with 1% BS&W, GOR of 47 scf/bbl through a 3-inch choke and an electro-submersible pump operating at 44 Hz.

Guama Block: 100% Interest

During the fourth quarter ended 2015, the Company continued extensive testing in Manamo-1X, Cotorra-1X, and Pedernalito-1X wells, producing 170.1 million cubic feet of natural gas and 5,442 barrels of condensate.

Farm-in and Farm-out Transactions and Acquisitions

Pacific Acquired the Remaining 50% Working Interest in the CPE-6 Block in Colombia

The Company, through its wholly-owned subsidiary Meta Petroleum Corporation, reached an agreement on December 17, 2015, with Talisman Colombia Oil & Gas Ltd. ("**Talisman**") to acquire the remaining 50% working interest held by Talisman in the CPE-6 Block in Colombia.

The price to be paid by the Company to Talisman is comprised of a royalty and cash payments based on production thresholds from the Block. Total cash consideration is entirely contingent on cumulative production and is capped at $48 million. Cash payments are distributed in three tranches based on the accumulated gross production thresholds of the Block. The first phase facilities are built and operating providing infrastructure to significantly increase production.

The CPE-6 Block is located in the highly prolific southern Llanos Basin of Colombia and it covers an area of approximately 240,000 hectares lying along the regional heavy oil trend, approximately 70 kilometers southwest of the Company's operated Rubiales and Quifa SW heavy oil fields.

Awarded with the Operating Agreement for Block 192 in Peru

Through its wholly-owned subsidiary, Pacific Stratus Energy del Peru S.A., the Company was awarded a two-year contract to operate Block 192 by Perupetro S.A. and initiated operations on August 30, 2015.

This is the largest producing oil block in Peru and it is located in the highly prolific Northern Marañon Basin, adjacent to the Peru-Ecuador international border. The block has been in production for 40 years, and had cumulative production of 725 MMbbl at the end of 2013. It has producing capacity of approximately 12,000 bbl/d and represents 17% of Peru's total oil production but is currently shut-in due to pipeline ruptures.

The Company's remuneration under the agreement is based on an R-factor calculation, which gives the Company a larger percentage of initial production and declines as the investment is recovered.

ALFA and Harbour Energy Offer to Acquire the Company

On May 21, 2015, the Company entered into an arrangement agreement with ALFA, S.A.B. de C.V. ("**ALFA**") and Harbour Energy Ltd. ("**Harbour Energy**"), pursuant to which a newly-formed company (the "**Purchaser**") jointly owned by ALFA and Harbour Energy would acquire all of the outstanding common shares of the Company, where each common share of the Company not already owned by ALFA would be acquired by the Purchaser for a cash consideration of C$6.50 per share.

After a comprehensive review of the offer, the Independent Committee of the Board of Directors determined, after receipt of advice from its financial and legal advisors, that the transaction was in the best interests of the Company and was considered fair to the Company's shareholders (other than ALFA and its affiliates), from a financial point of view.

On July 8, 2015, ALFA, Harbour Energy and the Company agreed to terminate the arrangement agreement.

Opportunities in Mexico

The Company signed a Memorandum of Understanding (MOU) with Pemex to jointly explore oil & gas in Mexico, establishing the basis for discussions and analysis of potential oil and gas cooperation in Mexico. In addition, the Company entered into an agreement with ALFA to create a joint venture that would allow the joint study, bidding or negotiation, acquisition and development of oil, gas and midstream assets in Mexico.

During the fourth quarter, the Company continued with the analysis of the current opportunities available given the current energy reform in Mexico. The Company has a specialized technical team focused on Round 1.

Throughout 2015, the Company worked actively in the first three phases of Round 1. In Phase-1, Shallow Water Exploration, the team evaluated 14 blocks, 4,412 kilometers of 2D seismic, 12,000 square kilometers of 3D seismic and 32 wells. In Phase-2, Shallow Water Extraction, we reviewed the information for five blocks, 1,000 kilometers of 2D seismic, 8,067 square kilometers of 3D seismic and 17 wells. In Phase-3, Onshore Exploitation, the Company analyzed 25 blocks, 70,588 kilometers of 2D seismic, 430 square kilometers of 3D seismic and 714 wells.

The Company will continue to assess the opportunities available to invest in Mexico.

Las Quinchas Holding Corp. sale

On November 20, 2015, Pacific Stratus International Energy Ltd. signed a share purchase agreement with Valle Energy Inc. relating to the sale of Las Quinchas Holding Corp. ("**Las Quinchas**") shares for a total amount of $39 million. The closing date for this transaction was December 18, 2015.

Farm-out Offering Portfolio Optimization

After an internal evaluation of the corporate portfolio of assets, the Company identified which blocks did not fit with its strategy, and in 2015 we initiated the offering process with interested parties. Offers have been received and are currently being evaluated in the context of the current oil market.

4 Financial Results

Revenues

(in thousands of US$)	Year Ended December 31 2015	Year Ended December 31 2014	Three Months Ended December 31 2015	Three Months Ended December 31 2014
Net crude oil and gas sales	$ 2,688,087	$ 4,546,359	$ 648,626	$ 888,930
Trading revenue	136,459	403,663	3,344	102,578
Total Sales	**$ 2,824,546**	**$ 4,950,022**	**$ 651,970**	**$ 991,508**
$ per boe oil and gas	48.51	85.35	41.22	65.64
$ per bbl trading	51.16	91.51	40.89	78.32
$ Total average revenue per boe	**$ 48.64**	**$ 85.82**	**$ 41.22**	**$ 66.75**

Revenues during 2015 were $2,825 million, 43% lower than 2014, revenues of $4,950 million. This decrease is the result of lower realized oil prices and lower trading volumes sold.

Revenues in the fourth quarter ended 2015 were $652 million, 34% lower than the same period in 2014 with revenues of $992 million. This decrease is the result of the significant drop in global oil prices.

The following is an analysis of the revenue drivers of price and volume for 2015 as compared to 2014:

	Year Ended December 31			
	2015	2014	Difference	% Change
Total of boe sold (Mboe)	58,076	57,679	397	1%
Avg. combined price - oil & gas and trading ($/boe)	48.64	85.82	(37.18)	-43%
Total Revenue	**2,824,546**	**4,950,022**	**(2,125,476)**	**-43%**

Drivers for the revenue decrease:		
Due to volume	$ 34,058	-2%
Due to price	(2,159,534)	102%
	$ (2,125,476)	

The following is an analysis of the revenue drivers of price and volume for the fourth quarter of 2015 as compared to the fourth quarter of 2014:

	Three Months Ended December 31			
	2015	2014	Difference	% Change
Total of boe sold (Mboe)	15,817	14,853	964	6%
Avg. combined price - oil & gas and trading ($/boe)	41.22	66.75	(25.53)	-38%
Total Revenue	**651,970**	**991,508**	**(339,538)**	**-34%**

Drivers for the revenue decrease:		
Due to volume	$ 64,381	-19%
Due to price	(403,919)	119%
	$ (339,538)	

Operating Costs

(in thousands of US$)	Year Ended December 31 2015	Year Ended December 31 2014	Three Months Ended December 31 2015	Three Months Ended December 31 2014
Production cost of barrels sold	$ 434,879	$ 805,397	$ 122,614	$ 185,675
Per boe	7.85	15.12	7.79	13.71
Transportation cost [1]	600,573	690,060	137,291	147,885
Per boe [1]	10.84	12.95	8.73	10.92
Diluent cost	113,141	115,121	33,345	24,540
Per boe	2.04	2.16	2.12	1.81
Other cost	50,522	22,073	16,323	2,186
Per boe	0.91	0.41	1.04	0.16
Royalties paid in cash	37,588	55,905	9,506	9,616
Per boe	0.68	1.05	0.60	0.71
Overlift/Underlift	35,445	(62,716)	35,324	(387)
Per boe	0.64	(1.18)	2.24	(0.03)
Operating cost	**1,272,148**	**$ 1,625,840**	**354,403**	**$ 369,515**
Average operating cost per boe	**$ 22.96**	**$ 30.51**	**$ 22.52**	**$ 27.28**
Take-or-pay fees on disrupted transport capacity Bicentenario	123,818	78,742	41,819	3,117
Per boe	2.23	1.48	2.66	0.23
Trading purchase cost	128,948	400,674	2,525	101,263
Per bbl	48.35	90.84	30.87	77.31
Total Cost	**$ 1,524,914**	**$ 2,105,256**	**$ 398,747**	**$ 473,895**

1. For the year and fourth quarter ended 2015, transportation costs on a boe basis include the Company's $54.5 million and $15.6 million, respectively, share of income from equity investments in the ODL and Bicentenario pipelines. Refer to Note 19 of the Audited Annual Consolidated Financial Statements for additional details.

Total operating costs for 2015 were $1,525 million, which includes the Company's $55 million share of income from equity investments in the ODL and Bicentenario pipelines, and $124 million ($2.23/boe) in net take-or-pay fees paid to Oleoducto Bicentenario de Colombia S.A.S. ("**Bicentenario**") when the capacity was not available. The Bicentenario pipeline was suspended for 204.5 days due to security issues. The Company utilized a combination of available capacity on the OCENSA pipeline and trucking to move oil to the export ports. For the fourth quarter of 2015, total operating costs were $399 million, a 16% decrease compared to $474 million for the same period of 2014.

Operating costs in 2015, excluding take-or-pay fees paid to Bicentenario and trading purchase costs were $1,272 million, $354 million lower as compared with $1,626 million in 2014. The reduction in costs resulted from cost optimization strategies adopted as a response to the lower oil price environment and COP depreciation against the U.S. dollar by 32% during 2015.

In addition, trading purchase costs decreased from $401 million in 2014 to $129 million in 2015 and from $101 million to $3 million in the fourth quarter of 2015 compared with the same period of 2014, mainly due to lower sales volumes and lower oil prices.

Depletion, Depreciation, and Amortization

(in thousands of US$)	Year Ended December 31 2015	Year Ended December 31 2014	Three Months Ended December 31 2015	Three Months Ended December 31 2014
Depletion, depreciation and amortization	$ 1,529,016	$ 1,641,577	$ 380,281	$ 475,952
$/per boe sales (own production)	27.60	30.82	24.17	35.14

DD&A costs for 2015 were $1,529 million, compared to $1,642 million in 2014. The decrease of 7% is primarily due to the impairment adjustments recognized during 2014. Unit DD&A for 2015 was $27.60/boe, 10% lower than $30.82/boe for 2014.

Impairment and Exploration Expenses

(in thousands of US$)	Year Ended December 31 2015	Year Ended December 31 2014	Three Months Ended December 31 2015	Three Months Ended December 31 2014
Impairment and exploration expenses	$ 4,907,209	$ 1,625,358	$ 3,890,229	$ 1,625,358
$/per boe sales (own production)	88.56	30.51	247.22	120.01

The Company assesses at the end of each reporting period whether there is any indication, from external and internal sources of information, that an asset or cash generating unit ("**CGU**") and/or goodwill may be impaired. Information the Company considers includes changes in the market, the economic and legal environment in which the Company operates that are not within its control and affect the recoverable amount of oil and gas, exploration and evaluation properties, and goodwill. Predominantly due to the significant and sustained decline in oil prices during 2015 and the Company's capitalization remaining below book value, the Company has determined that indicators of impairment existed as of December 31, 2015, and as such, has performed a test for recoverability of the value of the assets.

Internal sources of information include the manner in which long-lived assets are being used or are expected to be used, and indications of economic performance of the assets. Estimates include but are not limited to the discounted future after-tax cash flows expected to be derived from the Company's properties, costs to sell the properties, and the discount rate. Reductions in oil price forecasts, increases in estimated future costs of production, increases in estimated future capital costs, reductions in the amount of recoverable reserves, and resources and/or adverse current economics can result in a write-down of the carrying amounts of the Company's oil and gas, exploration, and evaluation assets and/or goodwill. An impairment loss is recognized when the carrying amount exceeds the recoverable amount.

The Company's impairment tests of oil and gas and exploration and evaluation assets are performed at the CGU level, as noted in the "Estimation Uncertainty and Assumptions" section of Note 2.1 to the Audited Annual Consolidated Financial Statements. The recoverable amount is calculated based on the higher of value in use and fair value less cost to sell. Value in use is predominantly derived from the future cash flows of the reserves and resources over the life of the blocks.

As at December 31, 2015, based on the impairment test performed by the Company, the carrying amounts of certain assets exceeded their recoverable amount, and as such, the Company concluded that a total of $4,641 million before tax of impairment charges would be recorded (2014: $1,432 million). The breakdown of the charges taken is as follows:

(in thousands of US$)	Year Ended December 31 2015	Year Ended December 31 2014
Oil and Gas Properties (D&P)		
Colombia properties	$ 2,020,927	$ 979,000
Peru properties	323,660	-
Plant and Equipment (PP&E)		
Guyana	-	4,200
Exploration and Evaluation Properties (E&E)		
Colombia properties	1,242,551	-
Peru properties	277,222	-
Other assets	539,196	65,800
Total Impairment Impact D&P, PP&E and E&E	**$ 4,403,556**	**$ 1,049,000**
Goodwill allocated to Colombia	237,009	375,000
Goodwill allocated to Guyana	-	8,000
Total impairment before tax	**$ 4,640,565**	**$ 1,432,000**

The recoverable amounts of the above CGUs are as follows: Central Colombia CGU: $1,237 million (December 31, 2014: $4,106 million); South Colombia CGU: $Nil (December 31, 2014: $228 million); Other non-Colombian CGU: $170 million (December 31, 2014: $208 million); Guyana ("**CGX**"): $Nil (December 31, 2014: $36 million).

The impairments recorded, excluding goodwill, may be reversed, in whole or in part, if and when the recoverable amount of the assets and CGUs increase in future periods.

The Company also incurred the following exploration expenses and impairment of financial assets:

- During the year ending December 31, 2015, through its subsidiary CGX, the Company incurred a $23.3 million fee for the termination of an offshore exploratory drilling contract. Pending certain regulatory approvals, $5.5 million was settled through the issuance of common shares of CGX in January 2016, $7.25 million is payable by March 25, 2016 and another $7.25 million is payable by June 15, 2016. The remaining $3.3 million has been recognized as a short-term accounts payable.
- During the year ending December 31, 2015, the Company decided to withdraw from its participation in the exploratory blocks in Papua New Guinea. As per the terms of the withdrawal, the Company agreed to accept a receivable of $96 million ($51.1 million present value, refer to Note 20 to the Audited Annual Consolidated Financial Statements), payable in six years from its partner in the blocks. As a result, the Company has recorded a charge of $114.3 million as exploration expense in the Consolidated Statement of Income for the year ending December 31, 2015.
- During 2015, the Company recorded approximately $49 million of changes against financial assets, including an allowance for amounts recoverable from a customer, impairments of certain available for sale financial assets, and write down of certain long-term receivables.

Total impairment and exploration expenses (before tax) are summarized below:

	Year Ended December 31		Three months Ended December 31	
(in thousands of US$)	2015	2014	2015	2014
Impairment	$ 4,640,565	$ 1,432,000	$ 3,772,556	$ 1,432,000
Impairment of financial assets	49,364	-	38,406	-
Exploration expenses	217,280	193,358	79,267	193,358
Total	**$ 4,907,209**	**$ 1,625,358**	**$ 3,890,229**	**$ 1,625,358**

General and Administrative Costs

	Year Ended December 31		Three Months Ended December 31	
(in thousands of US$)	2015	2014	2015	2014
General and administrative costs	$ 221,464	$ 360,681	$ 62,376	98,337
$/per boe sales	3.81	6.25	3.94	6.62

General and administrative ("**G&A**") costs decreased to $221 million in 2015 from $361 million in 2014, mainly due to the adoption of cost optimization initiatives. G&A per boe decreased by $2.44/boe to $3.81/boe from $6.25/boe in 2014.

For the fourth quarter of 2015, G&A was $62 million, a decrease of $36 million over the fourth quarter of 2014 ($98 million). As part of its strategy to adapt to the lower price environment, the Company initiated significant cost-cutting measures at the end of 2014 that carried through 2015. Cost optimization initiatives have continued into 2016.

Finance Costs and Foreign Exchange

	Year Ended December 31		Three Months Ended December 31	
(in thousands of US$)	2015	2014	2015	2014
Finance costs	$ 434,846	$ 261,300	$ 205,917	$ 73,738

Finance costs include interest on the Company's bank loans, senior notes, revolving credit facilities, working capital loans, finance leases, fees on letters of credit, and net of interest income received. For the year ended December 31, 2015, finance costs totaled $435 million compared with $261 million in 2014.

The increase in finance costs was mainly due to a $145 million write-off of deferred transaction costs and discount, and higher interest costs from the issuance of additional senior unsecured Notes in September 2014, and the revolving credit draw down in early 2015. Another factor that increased finance costs for the Company is that the revolving credit facility interest rate is variable according to the credit rating of the Company: since we experienced different downgrades from credit agencies during 2015, the interest rate of the facility changed from LIBOR + 2.25% for 2014 to LIBOR + 3.50%.

	Year Ended December 31		Three Months Ended December 31	
(in thousands of US$)	2015	2014	2015	2014
Foreign exchange loss	$ (134,477)	$ (63,211)	$ (21,396)	$ (52,239)

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 2015, the COP depreciated against the U.S. dollar by 32% as compared with a depreciation of 23% during 2014. Foreign exchange loss for 2015 was $134 million, compared with a loss of $63 million in 2014.

For the fourth quarter of 2015, foreign exchange represented a loss of $21 million compared with a loss of $52 million in the fourth quarter of 2014. The COP depreciated against the U.S. dollar by 1% in the fourth quarter of 2015, versus a depreciation of 18% in the same quarter of 2014.

Income Tax Expense

	Year Ended December 31		Three Months Ended December 31	
(in thousands of US$)	2015	2014	2015	2014
Current income tax	$ 50,226	$ 159,387	$ 7,909	$ (108,746)
Deferred income tax	(516,740)	29,349	(366,578)	(70,851)
Total income tax (recovery) expense	**$ (466,514)**	**$ 188,736**	**$ (358,669)**	**$ (179,597)**

The Canadian statutory combined income tax rate was 26.5% for the fourth quarter of 2015 and 2014.

The Colombian statutory tax rate for the fourth quarter of 2015 was 39% (2014: 34%), which includes the 25% general income tax rate and the fairness tax ("**CREE**") of 14% (2014: 9%). The Colombian Congress enacted new corporate tax rates for Colombian source income that are set to 39% in 2015, 40% in 2016, 42% in 2017, and 43% in 2018. As of January 1, 2019, the corporate tax rate will be reduced back to 34%. In addition, Congress introduced a temporary new wealth tax that accrues on net equity as of January 1, 2015, 2016, and 2017 at 1.15%, 1.00% and 0.40%, respectively.

The Peruvian statutory income tax rate was 28% and 30% for the quarters ended December 31, 2015 and 2014 respectively. The Peruvian income tax rate for Block Z-1 was 22% for the quarters ended December 31, 2015 and 2014. The Peruvian government passed major tax reforms on December 31, 2014, including a reduction in the general corporate tax rate to 28% for 2015 and 2016, 27% for 2017 and 2018, and 26% for taxation years 2019 and onwards.

The Company's effective tax rate differs from the statutory rate due to:

- 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), and the impairment losses in Colombia.
- Corporate expenses that result in tax loss carry-forwards; however, no deferred tax assets or recovery have been recognized. When the Company has a reasonable expectation to utilize these losses in the future, a deferred tax asset and a corresponding deferred tax recovery may be recognized, which would reduce the income tax expense.

- Foreign currency exchange rate fluctuations. The Company's functional and reporting currency is the U.S. dollar; however, the calculation of the income tax expense is based on income in the currency of the country of origin, i.e. Colombia, where the Company's assets are primarily located. As a result, the tax base of these assets is denominated in COP, and the related deferred tax balances are continually subject to fluctuations in the U.S.-COP exchange rate for IFRS purposes.
- The depreciation of the COP against the U.S. dollar by 1% during the fourth quarter of 2015, which resulted in an estimated unrealized deferred income tax expense of $25 million. In comparison, the Company recorded $243 million of unrealized deferred income tax recovery during the same period of 2014 as a result of the depreciation of the COP against the U.S. dollar by 18%.

Excluding the effect from the above-mentioned foreign exchange fluctuations (the Colombian portion, where the Company's assets are primarily located), the effective tax rate for the Company was 8.4% and 7.8% for the respective three-and twelve-month periods that ended December 31, 2015 and 10.9% and 22.7% for the respective three -and twelve-month periods that ended December 31, 2014.

	Year Ended December 31		Three Months Ended December 31	
(in thousands of US$)	**2015**	**2014**	**2015**	**2014**
Depreciation of the COP against the U.S. dollar (%)	(31.6)%	(24.2)%	(0.9)%	(17.9)%
Net loss before income tax	$ (5,949,485)	$ (1,146,099)	$ (4,274,842)	$ (1,864,328)
Current income tax expense	(50,226)	(159,387)	(7,909)	108,746
Deferred income tax recovery (expense) as reported	516,740	(29,349)	366,578	70,851
Total income tax recovery (expense) as reported	**466,514**	**(188,736)**	**358,669**	**179,597**
Excluding effect from depreciation of COP	-	313,304	-	243,339
Total income tax recovery excluding the above effects	**466,514**	**124,568**	**358,669**	**422,936**
Effective tax rate excluding effect of COP depreciation	**7.8%**	**10.9%**	**8.4%**	**22.7%**

In 2015, the Company did not recognize any deferred tax relating to foreign exchange fluctuations, therefore we are not reflecting these fluctuations in the deferred tax calculation.

Current income tax in Colombia totalled $50.2 million in 2015 as compared to $159.4 million in 2014. The reduction is mainly attributable to lower taxable revenues as a result of the significant drop in international oil prices.

The 2015 wealth tax paid totaled $39.1 million. Based on the Company's taxable base, the Company will not make an accrual for future years, pursuant to IAS 37 and IFRIC 21.

Capital Expenditures

	Year Ended December 31		Three Months Ended December 31	
(in thousands of US$)	**2015**	**2014**	**2015**	**2014**
Production facilities [(1)]	$ 132,856	$ 594,163	$ 47,584	$ 214,068
Exploration activities [(2)]	172,373	561,130	18,985	173,472
Early facilities and others	6,153	187,900	2,511	59,340
Development drilling	363,992	893,700	76,927	245,871
Other projects	50,138	145,403	14,147	65,091
Total capital expenditures	**$ 725,512**	**$ 2,382,296**	**$ 160,154**	**$ 757,842**

1. For 2014, includes investment in Maurel & Prom Colombia B.V., in which the Company holds a 49.999% participation.
2. Exploration activities for the 2015 includes drilling and seismic and other geophysical expenditures in Colombia, Peru, Brazil, and Papua New Guinea.

Capital expenditures during 2015 totaled $726 million, $1.7 billion lower than the $2.4 billion during 2014. A total of $133 million was invested in the expansion and construction of production infrastructure, primarily in Rubiales, Quifa SW, Cajua, Cubiro, Cravo Viejo, Sabanero, La Creciente, Guama, Corcel, Guatiquia, Orito, Casimena, and in the Block Z-1 fields; $173 million went into exploration activities including drilling and seismic and other geophysical activities in Colombia, Peru, Brazil, and Papua New Guinea; $6 million went into facilities and others; $364 million went into development drilling; and $50 million was invested in other projects.

In light of the current weak commodity price environment, since the second half of 2015 our capital expenditure programs have been cut back significantly to approximately equal cash flow. Our diversified portfolio of assets has the flexibility and discretionary components to allow us to scale back capital spending while maintaining production growth. In addition, the Company has also been successful in obtaining a significant reduction in its warranty deposits and bank letters of credit which support commitments to the ANH, from $223.7 million at the end of 2014 to approximately $111.0 million as of December 31, 2015.

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

	Year Ended December 31		Three Months Ended December 31	
(in thousands of US$)	2015	2014	2015	2014
Farm-in Agreement and others [(1)]	$ -	289,279	$ -	-
Total capital expenditures for new acquisitions	**$ -**	**$ 289,279**	**$ -**	**$ -**

1. For 2014, includes the acquisition of the remaining interest in the Cubiro and Arrendjo fields.

Financial Position

Debts and Credit Instruments

The following debts were outstanding as at December 31, 2015.

Senior Unsecured Notes

The Company has a number of series of senior unsecured notes outstanding with an aggregate principal of $4.1 billion as at December 31, 2015. 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.

Pursuant to the indentures governing the senior notes, the financial covenant prohibiting the incurrence of additional indebtedness of 3.5 times consolidated debt-to-EBITDA limits the Company's ability to incur additional debt, subject to various exceptions including certain refinancing transactions.

The senior notes represent almost 86% of the Company's outstanding debt.

Revolving Credit Facilities

On February 5 and March 13, 2015, the Company drew down $100 million and $900 million, respectively, from the $1 billion unsecured revolving Credit and Guaranty Agreement (the "**Revolving Credit Facility**"). Using the proceeds from the draw down, the Company repaid short-term bank loans in the aggregate principal amount of $383.8 million.

On March 3, 2015, the Company agreed with its syndicate of lenders to amend the Revolving Credit Facility. Under the amended terms of the Revolving Credit Facility, the Company's permitted consolidated leverage ratio (debt-to-EBITDA) was increased from 3.5:1.0 to 4.5:1.0 based on a rolling four-quarter average. The other two financial covenants were not amended, being: (i) the maintenance of an interest coverage ratio of greater than 2.5; and (ii) a net worth of greater than $1 billion, calculated as total assets less total liabilities, excluding those of certain subsidiaries, specifically Pacific Midstream Ltd. and Pacific Infrastructure Ventures Inc.

Under the terms of the Revolving Credit Facility and the Company's other credit facilities, the financial covenants are "maintenance-based covenants"; the Company must maintain compliance with the financial metrics in order to avoid default. For practical purposes, these are checked quarterly over a previous twelve-month basis. If at such time the financial debt ratios are not met, this may result in an acceleration in part or in whole of the indebtedness, or restrict the Company's ability to take on additional debt or carry out certain specified M&A operations, subject to various exemptions.

On September 29, 2015, the Company obtained a temporary waiver from its lenders under the Revolving Credit Facility and the other credit facilities with respect to the $1 billion net worth covenant. The waiver was subsequently extended to March 31, 2016 and amended to also provide a waiver of compliance with the debt-to-EBITDA covenant.

Covenant Breaches and Forbearance Agreements

On January 14, 2016, the Company announced it had elected to utilize the 30-day grace period under the applicable note indentures and not make interest payments of $66.2 million in the aggregate on the 2019 Senior Notes and the 2025 Senior Notes as they become due on January 26, 2016 and January 19, 2016, respectively. The failure to pay such interest constituted an event of default under the applicable note indentures on February 25, 2016 in respect of the 2019 Senior Notes and February 18, 2016 in respect of the 2025 Senior Notes. On February 18, 2016, the Company entered into an extension agreement with certain holders of the 2019 and 2025 Senior Notes. Under the terms of the Noteholder Extension Agreement, holders of approximately 34% of the aggregate principal amount of outstanding 2019 Senior Notes and 42% of the aggregate principal amount of outstanding 2025 Senior Notes have agreed, subject to certain terms and conditions, to forbear from declaring the principal amounts of the notes (and certain additional amounts) due and payable as a result of certain specified defaults until March 31, 2016.

In addition, lenders under the (i) $1 billion revolving credit and guaranty agreement with a syndicate of lenders and Bank of America, N.A, as administrative agent; (ii) $250 million credit and guaranty agreement with HSBC Bank USA, N.A., as agent; (iii) $109 million credit and guaranty agreement with Bank of America, N.A., as lender; and (iv) $75 million master credit agreement with Banco Latino Americano de Comercio Exterior, S.A. ("**Bladex**"), as lender (collectively, the "**Credit Agreements**"), have agreed to enter into the Lender Forbearance Agreements pursuant to which such lenders have agreed, subject to certain terms and conditions, to forbear from declaring the principal amounts of the Credit Agreements due and payable as a result of certain specified defaults until March 31, 2016.

On November 27, 2015 the Company agreed with Bladex to prepay the Bladex credit facility in the amount of $50.6 million, and in return, Bladex provided Letters of Credit for the same amount. Subsequent to December 31, 2015, the Company made two additional prepayments, on January 8, 2016 for $17.2 million and on February 3, 2016 for $7.1 million, at which time the Bladex facility was fully repaid and cancelled.

Letters of Credit

As at December 31, 2015, the Company had issued letters of credit and guarantees for exploration and operational commitments for a total of approximately $272 million.

Oil Price-Hedging

In the fourth quarter, realized gains from oil price-hedging totaled $146.9 million on 10.1 MMbbl of notional volume, representing $9.34/bbl in higher crude realized prices during the quarter. The average floor prices for the settled hedges were $55.84/bbl for WTI sales and $60.90 bbl for Brent sales. For the year ended December 31, 2015, cumulative realized gains from oil price hedging amounted to $289.6 million.

As part of the active management of the hedging portfolio, the Company undertook a defensive unwinding strategy in February 2016 that not only strengthened the cash position of the Company, but also maximized the cash value of the outstanding hedging portfolio of 7.65 MMbbl.

Outstanding Share Data

Common Shares

As at March 16, 2016, 316,094,858 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 March 16, 2016, there were no warrants outstanding. 12,631,367 stock options were outstanding, of which all were exercisable. As of May 28, 2014, the Board of Directors 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 March 16, 2016, there were 6,793,699 DSUs outstanding. 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 Company.

Liquidity and Capital Resources

Funds flow provided by operating activities for 2015 totalled $579 million (2014: $2,021 million). The decrease in funds flow in 2015 compared with the same period of 2014 was mainly the result of a decrease in oil prices.

As at December 31, 2015, the Company had negative working capital of $5,455 million, mainly comprised of $343 million in cash and cash equivalents, $18 million in restricted cash, $518 million in accounts receivable, $27 million in inventory, $201 million in income tax receivable, $5 million in prepaid expenses, $173 million in risk management assets, $1,217 million in accounts payable and accrued liabilities, $75 million in deferred revenue net proceeds, $1 million in income tax payable, $5,377 million in the current portion of long-term debt, $14 million in the current portion of obligations under finance lease, $53 million in risk management liability and $3 million in asset retirement obligation.

In March 2015, the Company entered into an agreement with a customer to deliver six million barrels of crude oil over the six-month period from April to September 2015. A prepayment of $200 million (less $0.53 million in fees) was advanced to the Company in March 2015 representing a prepayment of $33.33 per barrel of oil. This agreement was fully settled during 2015.

On June 30, 2015, the Company entered into a second agreement with the same customer to deliver another six million barrels of oil over the six-month period from October 2015 to March 2016. A prepayment of $100 million (less $0.32 million in fees) was advanced to the Company on June 30, 2015. An additional prepayment of $50 million was advanced in July 2015 for a total of $150 million or $25.00 per barrel of oil.

Please refer to "Financial Results – Financial Position" on page 20 for details of certain events of default, covenant breaches and forbearance agreements in respect of the Company's outstanding indebtedness, and to "Risks and Uncertainties" on page 39 for details of the risks and uncertainties relating to the Company's liquidity and capital resources and ability to continue as a going concern.

5 Proved and Probable Oil and Gas Reserves

For the year ending December 31, 2015, the Company received independent certified reserves evaluation reports for all of its assets, establishing that total net 2P reserves had decreased to 290.8 MMboe from 510.9 MMboe. This represents a 43% year-on-year decline mainly due to the significantly lower oil price forecasts resulting in economic revisions plus the impact of normal course technical revisions as assessed by the Company's independent reserves evaluators. Proved net reserves of 197.8 MMboe now represent 68% of the total 2P reserves compared to 62% in 2014.

The table below summarizes information contained in the following independent-reserves reports:

1. RPS Energy Canada Ltd. prepared: (i) the report dated February 16, 2016, effective December 31, 2015, entitled "Reserves Certification Report, Year End 2015, Quifa SW Field, Llanos Basin - Colombia"; (ii) the report dated February 16, 2016, effective December 31, 2015, entitled "Reserves Certification Report, Year End 2015, Cajua Field, Llanos Basin - Colombia"; (iii) the report dated February 16, 2016, effective December 31, 2015, entitled "Reserves Certification Report, Year End 2015, Jaspe Field, Llanos Basin - Colombia"; (iv) the report dated February 16, 2016, effective December 31, 2015, entitled "Reserves Certification Report, Year End 2015, Prospect D Field, Llanos Basin - Colombia"; (v) the report dated February 16, 2016, effective December 31, 2015, entitled "Reserves Certification Report, Year End 2015, Rubiales Field, Llanos Basin - Colombia"; (vi) the report dated February 16, 2016, effective December 31, 2015, entitled "Reserves Certification Report, Year End 2015, Rio Ariari Field, Llanos Basin - Colombia"; (vii) the report dated February 16, 2016, effective December 31, 2015, entitled "Reserves Certification Report, Year End 2015, Hamaca Field, Llanos Basin - Colombia"; and (viii) the report dated February 16, 2016, effective December 31, 2015, entitled "Reserves Certification Report, Year End 2015, Sabanero Field, Llanos Basin - Colombia"; (collectively, the "**RPS Report**").

2. Netherland Sewell & Associates, Inc. prepared the report dated February 22, 2016, effective December 31, 2015, entitled "Estimates of Reserves and Future Revenue to the Pacific Stratus Energy S.A. Interest in Certain Oil Properties Located in Albacora and Corvina Fields Offshore Peru and blocks 131 and 192, Onshore Peru" (the "**NSAI Report**").

3. DeGolyer and MacNaughton Limited prepared: (i) the report dated February 12, 2016, effective December 31, 2015, entitled "Report as of December 31, 2015 on Reserves and Revenue of Certain Properties in Colombia for Pacific Stratus Energy, Executive Summary, NI 51-101" (the "**D&M Report**" and together with the RPS Report and the NSAI Report, the "**Reserves Reports**").

   The Reserves Reports were prepared in accordance with the definitions, standards, and procedures contained in the Canadian Oil and Gas Evaluation Handbook ("**COGE Handbook**") and the National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**").

Additional reserves information as required under NI 51-101 are included in the Company's Annual Information Form dated March 18, 2016.

Reserves at December 31, 2015 (MMboe[1])								
Country	**Field**	**Proved (P1)**		**Probable (P2)**		**Proved + Probable (2P)**		**Hydrocarbon Type**
		Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	
Colombia	Rubiales	11.5	9.2	-	-	11.5	9.2	Heavy Oil
	Other Heavy Oil Blocks[2]	101.0	88.8	40.2	34.5	141.3	123.3	Heavy Oil
	Light/Medium Oil Blocks	53.3	49.0	29.8	27.4	83.1	76.4	Light & Medium Oil, Associated Natural Gas
	Natural Gas Blocks[3]	40.4	40.3	13.7	13.7	54.1	54.1	Natural Gas
	Sub-total	**206.2**	**187.4**	**83.8**	**75.6**	**290.0**	**263.0**	Oil & Natural Gas
Peru	Light/medium oil/natural gas[4]	10.4	10.4	17.4	17.4	27.8	27.8	Oil & Natural Gas
	Total at Dec. 31, 2015	**216.6**	**197.8**	**101.2**	**93.0**	**317.8**	**290.8**	Oil & Natural Gas
	Total at Dec. 31, 2014	348.9	315.0	211.7	195.9	560.6	510.9	
	Difference	**(132.3)**	**(117.3)**	**(110.5)**	**(102.8)**	**(242.8)**	**(220.1)**	
	2015 Production	64.4	56.4	**Total Reserves Incorporated**		**(178.4)**	**(164.2)**	

1. See "Boe conversion" on the "Advisories" section, page 45.
2. Includes Quifa SW, Cajua, Jaspe, Quifa North, Sabanero, Hamaca and Rio Ariari properties.
3. Includes La Creciente field.
4. Includes onshore Block 131, Block 192, and offshore Block Z1.

In the table above, "Gross" refers to WI before royalties, and "Net" refers to WI after royalties. Numbers in the table may not add due to rounding differences.

6 Project Status Review

The following is an update on the current status and working-interest share of costs incurred as of December 31, 2015 for the Company's major projects.

Project	Project financed by	As of December 31, 2015 Total cost to complete the project	Cost incurred to date	Expected future costs to incur
Bicentenario pipeline	Equity and debt combination	761,631	709,134	52,497
PEL-Power transmission line project	Equity and debt combination	240,600	232,100	8,500
Water treatment for agricultural development	Equity and debt combination	170,000	118,642	51,358
Puerto Bahia Project	Equity and debt combination	250,733	249,229	1,504
		$ 1,422,964	**$ 1,309,105**	**$ 113,859**

Bicentenario Pipeline

As of December 31, 2015, Phase One of the project is completed and approximately 34.8 MMbbl have been pumped through the pipeline. During the fourth quarter, the pipeline transported at an average rate of 31,763 bbl/d. The truck unloading station project in Araguaney is in normal operation with a capacity of 40,000 bbl/d. The project reached final completion at December 31, 2015, with a total capitalized cost of $1,648 million.

ODL Pipeline

In October 2015, a new truck unloading station was completed in the Jagüey Booster Station of ODL, allowing crude oil from a third-party producing company to be transported in the ODL pipeline. This is the first time since ODL started operations in 2009 that third parties nominated and transported volumes in this pipeline.

PEL – Power Transmission Line Project

The PEL power line commenced operation on January 20, 2014, and as at December 31, 2015, the line has transmitted 1,599,989 MWh to the Rubiales and Quifa fields, and EBR and Jagüey Substation, owned by ODL. The availability of the system has been 99.9 %. As of the date of this report, the Quifa and Jagüey substations are completed and in normal operation. Construction of Corocora substation has been deferred due to oil market environment and current situation of the domestic energy market.

Studies have been completed on increasing PEL transmission capacity from 192 MW to 262 MW, and the increase was approved by Empresa de Energía de Bogotá and by Unidad de Planeación Minero Energética, subject to certain upgrades that must be performed in the national grid prior to implementation. The completion of the project is planned for 2017 and will allow for future development of the Llanos Basin.

Caribbean Floating LNG Project

Due to the current oil and gas market environment, this project has been deferred. In March 2016 the Company and Exmar NV agreed, pursuant to a settlement agreement, to terminate a Liquefaction and Storage Agreement, originally executed in March 2012 for a term of 15 years, from delivery of a floating liquefaction unit ("**CFLNG**") with a liquefaction capacity of approximately 0.5 million tons per annum of Liquefied Natural Gas ("**LNG**") and a storage volume of 16,100 cubic meters (the "**Tolling Agreement**").

The settlement agreement stipulates a termination fee payable by the Company to Exmar in monthly installments from March 2016 until June 2017. Additionally, any and all obligations in connection with the Tolling Agreement have been terminated, except for customary survival clauses (e.g. confidentiality and dispute resolution).

Agrocascada Project: Water Treatment for Agricultural Development

As of September 30, 2015, the construction of the first reverse osmosis water treatment plant was completed. As at December 31, 2015, the permits for the water concession were granted by the local environmental authority ("**Cormacarena**"), commissioning activities have restarted in early 2016 in one of the plants.

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

Agrocascada is expected to be operational in the second quarter of 2016.

Pacific Infrastructure: Puerto Bahía Terminal

The Company has a 41.79% equity interest in Pacific Infrastructure Ventures Inc. ("**PII**"), a private company that owns Puerto Bahía, an oil export/import terminal located in Cartagena Bay in Colombia.

In May 2015, operations approval from the Minister of Energy and Mines was obtained. The port began operations in June 2015, receiving oil trucks and oil tankers. On August 28, 2015, the official inauguration event of the port took place with the Vice President of Colombia as well as National and Regional Authorities in attendance.

As at December 31, 2015, construction activities for the liquids terminal have progressed to 99.2%. The truck loading and unloading station, the fixed bridge and the multi-purpose terminal for handling bulk materials are completed. The port has 8 of its 10 planned tanks in full operation for a capacity of 3 MMbbl. To the end of 2015, the largest vessel received by the port was a Suezmax oil tanker with capacity of one million barrels.

The operations in Puerto Bahía have generated new opportunities currently being analyzed, related to handling crude oil and products for the neighbouring Cartagena Refinery.

7 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 year ending December 31, 2015, the amounts reassessed, including interest and penalties, is estimated at $59.8 million, of which the Company estimates that $21.9 million should be assumed by companies that share interests in these contracts. The Company disagrees with the DIAN’s reassessment and official appeals have been initiated. Several other taxation periods dating 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 $59.8 million and $120 million. Of that amount, the Company estimates between $31.8 million and $53.8 million should be assumed by other companies that share interests in these contracts.

On February 24, 2016, the DIAN issued a ruling which concluded that the internal consumption of oil produced does not create an IVA obligation. The Company expects the current dispute regarding IVA to be resolved in its favour, and as such no provision has been recognized in the consolidated financial statement. The Company continues to utilize oil produced for internal consumption, which is an accepted practice for the oil industry in Colombia.

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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 at December 31, 2015, the DIAN has reassessed $56.3 million of tax owing, including estimated interest and penalties, with respect to the denied deductions.

As at December 31, 2015, the Company believes that the disagreements with the DIAN related to the denied income tax deductions will be resolved in favour of the Company. No provision with respect to income tax deductions under dispute has been recognized in the consolidated financial statements.

Equity Tax

Effective January 1, 2015, the Colombian Congress introduced a new wealth tax that is calculated on a taxable base (net equity) in excess of COP $1 billion ($0.4 million) as at January 1 of the applicable taxation year. The applicable rates for January 1, 2015, 2016, and 2017 are 1.15%, 1.00% and 0.40%, respectively. Based on the Company’s taxable base, the Company has accrued a liability for the 2015 fiscal year. Pursuant to IAS 37 and IFRIC 21, in the current year the Company has not made an accrual for future years. The 2015 wealth tax has been estimated at $39.1 million, and recorded as an expense in the statement of income. In May 2015, the Company made the first payment of $20.5 million, and in September 2015 the remaining payment of $18.6 million was made.

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 37 for details relating to this contingency.

Minimum Credit Rating Requirement

The Company has an assignment agreement with Transporte Incorporado S.A.S. ("**Transporte Incorporado**"), a Colombian company owned by an unrelated international private equity fund. Transporte Incorporado owns a 5% equity interest and capacity right in the OCENSA pipeline in Colombia. Under the assignment agreement, the Company is entitled to use Transporte Incorporado's capacity to transport crude oil through the OCENSA pipeline for a set monthly premium until 2024. Pursuant to the assignment agreement, the Company is required for the duration of the agreement to maintain a minimum credit rating of Ba3 (Moody's), which was breached in September and December 2015 and January 2016 when Moody's downgraded the Company's credit rating to B3, Caa3 and C, respectively. As a result of the downgrade and in accordance with the assignment agreement, upon giving notice to the Company, Transporte Incorporado would have the right to early-terminate the assignment agreement and the Company would be required to pay an amount determined in accordance with the agreement, estimated at $129 million. The Company has not received such notice from Transporte Incorporado, and on January 6, 2016, the Company received a waiver from Transporte Incorporado of its right to early-terminate for a period of 45 days until February 15, 2016, which was further extended several times to March 18, 2016. The Company continues to pay monthly premiums. No provision has been recognized as of December 31, 2015 relating to the breach of the credit rating requirement.

In Colombia, the Company is participating in a project to expand the OCENSA pipeline, which is expected to be completed and commence operation in July 2016. As part of the expansion project, the Company, through its subsidiaries Meta Petroleum and Petrominerales Colombia, entered into separate crude oil transport agreements with OCENSA for future transport capacity. The Company will start paying ship-or-pay fees once the expansion project is complete and operational. As part of the transport agreements, the Company is required to maintain minimum credit ratings of BB- (Fitch) and Ba3 (Moody's). This covenant was breached in September and December 2015 and January 2016 when Moody's downgraded the Company's credit rating to B3, Caa3 and C respectively. As a result of the downgrades and pursuant to the transport agreements, upon giving notice to the Company, OCENSA has the right to require the Company to provide a letter of credit or proof of sufficient equity or working capital within a cure period of 60 days starting from the day on which notice is received by the Company. On November 5, 2015, the Company received a waiver from OCENSA of its rights to receive a letter of credit which will expire once the project is complete and operational. No provision has been recognized as of December 31, 2015 relating to the breach of the credit rating requirement.

In March 2012, the Company's subsidiary Pacific Stratus Energy Colombia Corp ("**PSE**") entered into a liquefaction, storage and loading services agreement ("**Tolling Agreement**") with Exmar NV ("**Exmar**"). The Company as part of the agreement is required to maintain a minimum credit rating of BB- (Standards and Poor's). This covenant was breached in December 2015 when Standards and Poor's downgraded the Company's credit rating to CCC+. As a result of the downgrade and pursuant to the agreement, upon giving notice to the Company, Exmar can request a letter of credit for approximately $53.6 million. As at December 31, 2015 PSE and Exmar were in negotiations regarding the minimum credit rating requirement, and early termination of the agreement. The Company has recognized a provision of $20 million based on its best estimate of the cost for early termination. In March 2016, the Company and Exmar agreed to terminate the Tolling Agreement, and the Company agreed to pay a termination fee of $5 million in cash up front and $1 million per month for a period of 15 months. Any and all obligations in connection with the Tolling Agreement have been terminated.

Commitments

The Company is involved in various claims and litigation arising in the normal course of business. Because the outcome of these matters is uncertain, there can be no assurance that such matters will be resolved in the Company's favour. The Company does not currently believe that the outcome of adverse decisions in any pending or threatened proceedings related to these and other matters or any amount which it may be required to pay by reason thereof would have a material impact on its financial position, results of operations or cash flows.

Disclosures concerning the Company's significant commitments can be found in Note 25 to the Audited Annual 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 28 to the Audited Annual Consolidated Financial Statements.

8 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: Hernan Martinez (Chair), Alejandro Betancourt, Dennis Mills, and Jesus Valdez Simancas. 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, is considered similar to those negotiable with third parties.

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

a) During the year ending December 31, 2015, the Company received cash of $58 million in accordance with its joint operations obligation associated with its 49% interest in Block Z-1 in Peru. In addition, the Company had accounts receivable of $0.3 million under the joint operation agreement from Alfa SAB de CV ("**Alfa**"), which owns a 51% working capital interest in Block Z-1 and also holds 19.2% of the issued and outstanding capital of the Company.

b) On December 11, 2015, the Company and the other shareholders of Pacific Power Generation Corp. ("**Pacific Power**"), including Proenergy Corp. (a subsidiary of Blue Pacific Assets Corp. ("**Blue Pacific**")), entered into a share purchase agreement with Faustia Development S.A., Tusca Equities Inc. and Associated Ventures Corp. (the "Pacific Power Purchasers"), for the sale of 70% of the shares of Pacific Power. As part of the transaction, the Company agreed to sell 4% of the Company's 24.9% equity interest in Pacific Power to the Pacific Power Purchasers for approximately $5.0 million. As a result of the sale, the Company currently owns approximately 21% and Proenergy Corp. (Blue Pacific) currently owns approximately 5% of Pacific Power. Associated Ventures Corp. is controlled by Alejandro Betancourt, a director of the Company.

   The Company used most of the proceeds from the sale to pay for its share of a put option that was exercised by Sustainable Services Inc., pursuant to the terms of a pre-existing shareholder agreement between Pacific Power and its shareholders. The Company did not bear any of the transaction costs of approximately $1.3 million, and was not subject to withholdings for its pro rata share of any of the Pacific Power debt that may have been accelerated as a part of the transaction.

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 Promotora de Energia Electrica de Cartagena & Cia S.C.A.E.S.P ("**Proelectrica**"), in which the Company has a 21.1% indirect interest, and Genser Power Inc. ("**Genser**") which is 51% owned by Pacific Power. On March 1, 2013, these contracts were assigned to TermoMorichal SAS ("**TermoMorichal**"), the company created to perform the agreements, in which Pacific Power has a 51% indirect interest. Total commitment under the BOMT agreements is $229.7 million over ten years. In April 2013, the Company and Ecopetrol entered into another agreement with Genser-Proelectrica to acquire additional assets for a total commitment of $57 million over ten years. At the end of the Rubiales Association Contract in 2016, the Company's obligations along with the power generation assets will be transferred to Ecopetrol. During the year ending December 31, 2015, the Company paid $30.6 million (2014: $14.5 million) under the Rubiales Association Contract. As at December 31, 2015, the Company had an advance of $3.3 million (December 2014: $7.6 million).

   During the year ending December 31, 2015, $2.5 million was expensed in relation to the power generation cost concept (2014: $Nil). The Company had accounts payable of $3.6 million (December 2014: $5.9 million) due to Genser-Proelectrica as at December 31, 2015. In addition, on May 5, 2014, a subsidiary of the Company provided a guarantee in favour of XM Compañia 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. In December 2014, the Company entered into a new contract with Genser related to the operation and maintenance of the power generation facility located in the Sabanero field.

   In October 2013, the Company entered into connection agreements and energy supply agreements with Proelectrica for the supply of power to the oil fields in the Llanos basin. The connection agreements authorize Meta Petroleum Corp. and Agro Cascada S.A.S. to use the connection assets of Petroelectrica for power supply at the Quifa and Rubiales fields. The agreement commenced on November 1, 2013 and will operate for 13 years. During the year ending December 31, 2015, the Company made payments of $46.3 million (2014: $69.1 million) under this agreement.

   The Company has entered into several take-or-pay agreements as well as interruptible gas sales and transport agreements to supply gas from the La Creciente natural gas field to Proelectrica's gas-fired plant. During the year ending December 31, 2015, the Company recorded revenues of $9.3 million (2014: $13.4 million) from such agreements. As at December 31, 2015, the Company had trade accounts receivable of $12.3 million (December 2014: $7.5 million) from Proelectrica.

   Under the energy supply agreements, Proelectrica provides electricity to the Company for power supply at the Quifa and Rubiales fields, with payments to be calculated monthly on a demand-and-deliver basis. The term of the agreement is until December 31, 2026. The aggregate estimated energy supply agreement is for 1.5 million kilowatts.

d) As at December 31, 2015, the Company had trade accounts receivable of $12.3 million (December 31, 2014: $7.5 million) from Proelectrica, in which the Company has a 21.1% indirect interest and which is 5% owned indirectly by Blue Pacific. The Company and Blue Pacific's indirect interests are held through Pacific Power. Revenue from Proelectrica in the normal course of the Company's business was $9.3 million for the year ending December 31, 2015 (2014: $13.4 million). Two directors and an officer of the Company (Serafino Iacono, Miguel de la Campa, and Laureano von Siegmund), along with Jose Francisco Arata a director until August 14, 2015, control, or provide investment advice to the holders of approximately 76% of the shares of Blue Pacific.

e) As at December 31, 2015, loans receivable from related parties in the aggregate amount of $0.5 million (December 31, 2014: $0.9 million) are due from one executive director (Serafino Iacono) and seven officers (Carlos Perez, Luis Andres Rojas, Francisco Bustillos, Luciano Biondi, Jairo Lugo and Marino Ostos) of the Company. The loans are non-interest bearing and payable in equal monthly payments over a 48-month term.

   In August 2015, the Company agreed to pay $8.3 million in severance to one of its officers (Jose Francisco Arata), who retired from the Company on August 14, 2015, which included $5.5 million in cash paid during 2015, and $2.8 million payable in March 2016. In addition, the departing officer's DSU entitlement was paid in kind with the Company's shares held in treasury on a one-to-one basis, for a total of approximately 1.3 million common shares. Also during 2015, the Company also made payments in kind of approximately 0.5 million common shares to three departing directors (Victor Rivera, Miguel Rodriguez and Neil Woodyer) as settlement for DSU entitlements.

f) During the year ending December 31, 2015, the Company paid $108.5 million to ODL (2014: $165 million) for crude oil transport services under the pipeline take-or-pay agreement and had accounts payable of $13.1 million (December 31, 2014: $Nil). In addition, the Company received $2.9 million from ODL during the year ending December 31, 2015 (2014: $2.6 million) with respect to certain administrative services and rental equipment and machinery. The Company has accounts receivable from ODL as at December 31, 2015 of $0.1 million (December 31, 2014: $0.4 million). The Company has an approximately 22% indirect interest in ODL.

g) During the year ending December 31, 2015, the Company paid $155.6 million to Oleoducto Bicentenario de Colombia S.A.S. (2014: $174.4 million), a pipeline company in which the Company has a 27.9% interest, for crude oil transport services under the pipeline ship-or-pay agreement. As at December 31, 2015, the balance of loans outstanding to Bicentenario was $Nil (December 31, 2014: $42 million). Interest income of $1.3 million was recognized during the year ending December 31, 2015 (2014: $2.7 million). Interest of $2.1 million was paid on the loans during the year ending December 31, 2015 (December 31; 2014: $5.9 million), and capital of $42 million was paid on the loans in the year ending December 31, 2015. During the year ending December 31, 2015, the Company received $Nil (2014: $0.6 million) with respect to certain administrative services, rental equipment, and machinery. The Company has advanced $87.9 million as at December 31, 2015 (December 31, 2014: $87.9 million) to Bicentenario as a prepayment of transport tariff, which will be amortized against the barrels transported. As at December 31, 2015, the Company had trade accounts receivable of $0.4 million (December 31, 2014: $13.7 million) as a short-term advance.

h) The Company has established two charitable foundations in Colombia: the Pacific Rubiales Foundation and the Foundation for Social Development of Energy Available ("**FUDES**"). Both foundations have the objective of advancing social and community development projects in the country. During the year ending December 31, 2015, the Company contributed $15.3 million to these foundations (2014: $43.7 million). As at December 31, 2015, the Company had accounts receivable (advances) of $0.4 million (December 31, 2014: $5.0 million) and accounts payable of $3.2 million (December 31, 2014: $8.7 million). Three of the Company's directors (Ronald Pantin, 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) At as December 31, 2015, the Company had demand loans receivable from PII in the amount of $72.4 million (December 31, 2014: $71.4 million). The loans are guaranteed by PII's pipeline project and bear interest that ranges from LIBOR + 2% to 7% per annum. The Company owns 41.65% of PII. In addition, during the year ending December 31, 2015, the Company received $3.7 million (2014: $1.3 million) from PII with respect to contract fees for advisory services and technical assistance in pipeline construction of "Oleoducto del Caribe." In addition, as at December 31, 2015, the Company had accounts receivable of $0.5 million (December 31, 2014: $1.0 million) from Pacific Infrastructure Ventures Inc., a branch of PII. As at December 31, 2015, the Company had accounts payable of $0.5 million to PII (December 31, 2014: $Nil).

In December 2012, the Company entered into a take-or-pay agreement with Sociedad Puerto Bahia S.A., a company that is wholly owned by PII. Pursuant to the terms of the agreement, Sociedad Puerto Bahia S.A. will provide for the storage, transfer and loading and unloading of hydrocarbons at its port facilities. The contract term commenced in 2014 and will continue for seven years, renewable in one-year increments thereafter. These agreements may indirectly benefit Blue Pacific and other unrelated minority shareholders of PII. During the year ending December 31, 2015, the Company advanced $28.6 million to Sociedad Puerto Bahía S.A. (2014: $Nil), of which $10.9 million was expensed during the year ending December 31, 2015, in relation to services received (2014: $Nil).

j) In October 2012, the Company entered into an agreement with Pacific Coal (now called Caribbean Resources Corp. ("**CRC**")), Blue Advanced Colloidal Fuels Corp. ("**Blue ACF**"), Alpha Ventures Finance Inc. ("**AVF**"), and an unrelated party whereby the Company acquired from CRC the right to a 5% equity interest in Blue ACF for a cash consideration of $5 million. Blue ACF is a company engaged in developing colloidal fuels; its majority shareholder is AVF, which is controlled by Blue Pacific. As part of the purchase, CRC also assigned to the Company the right to acquire up to an additional 5% equity interest in Blue ACF for an additional investment of up to $5 million. The Company currently has an 8.49% equity interest in CRC. In addition, the Company has an indirect equity interest of 8.61% in CRC through its 21.1% ownership of Pacific Power, which in turn has a 40.86% equity interest in CRC. Hernan Martinez, a director of the Company, is the Executive Chairman of CRC.

k) Blue Pacific provides the Company with passenger air transport services on an as-needed basis. During the year ending December 31, 2015, the Company paid $Nil (2014: $0.2 million) for these services.

l) The Company has a lease agreement for an office in Caracas, Venezuela for approximately $6 thousand per month. The office space is 50% owned by a family member of an executive officer of the Company (Laureano von Siegmund).

9 Selected Quarterly Information

	2015				2014				2013	
(in thousands of US$ except per share amounts)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Financials:										
Net sales	$ 651,970	$ 669,995	$ 702,733	$ 799,848	$ 991,508	$ 1,330,395	$ 1,344,666	$ 1,283,453	$ 1,202,551	$ 1,109,973
Net (loss) earnings attributable to equity holders of the parent for the period	(3,895,908)	(617,318)	(226,377)	(722,256)	(1,660,876)	3,484	228,527	119,240	140,412	84,013
(Loss) Earnings per share										
- basic	(12.37)	(1.97)	(0.72)	(2.31)	(5.26)	0.01	0.73	0.38	0.43	0.26
- diluted	(12.37)	(1.97)	(0.72)	(2.31)	(5.26)	0.01	0.72	0.37	0.43	0.26

10 Accounting Policies, Critical Judgments, and Estimates

Basis of Presentation

The Audited Annual Consolidated Financial Statements accompanying this MD&A for the years ending December 31, 2015 and 2014 have been prepared in accordance with International Financial Reporting Standards (“**IFRS**”) as issued by International Accounting Standards Board (“**IASB**”), including the accounting policies and critical judgments and estimates as disclosed in Note 2 of the Audited Annual Consolidated Financial Statements.

The Audited Annual Consolidated Financial Statements were prepared on a going concern basis that contemplated the realization of assets and the settlement of liabilities in the normal course of business as they become due, except for the revaluation to fair value of certain financial assets and financial liabilities in accordance with the Company’s accounting policies.

For the year ended December 31, 2015, the Company incurred a net loss of $5,482.9 million and had a deficit of $2,990 million as of December 31, 2015, primarily due to impairment charges recorded during the year.

Since late 2014, the Company has implemented a number of cost reduction initiatives in response to the prevailing low crude oil prices, including:

- Significantly reduced operating and general and administrative expenses;
- Lowered the 2016 capital expenditure budget;
- Engaged in ongoing debt restructuring negotiations; and
- Continued negotiations on non-core asset sales.

Despite the above initiatives, at current crude oil prices, the Company will likely need new financing to fund its interest payments and debt repayments as they come due, and possibly operating cash needs. The Company currently has in place forbearance agreements with certain holders of its senior notes and revolving and bank credit facilities, whereby the credit parties under these agreements have agreed to forbear from declaring the principal amounts due and payable as a result of certain specified defaults until March 31, 2016. The Company continues to engage with creditors on restructuring the capital structure to be more suitable to current market conditions.

The Company has also breached several minimum credit rating covenants in respect of certain operational agreements it has entered into, as a result of downgrades of the Company’s credit rating during 2015. Consequently, the counterparties of these operational agreements have the option to demand a range of remedies including letters of credit and penalties. Waivers related to these credit rating covenants have been granted (refer to Note 25 of the Audited Annual Consolidated Financial Statements).

There can be no certainty as to the ability of the Company to successfully restructure its long-term debts, amend the applicable operating agreements to eliminate the credit rating covenants, and obtain new financing should low crude prices persist, and accordingly, there is a material uncertainty that may cast doubt on the Company’s ability to continue as a going concern. The Audited Annual Consolidated Financial Statements do not include adjustments to the recoverability and classification of recorded assets and liabilities and related expenses that might be necessary should the Company be unable to continue as a going concern and therefore be required to realize its assets and liquidate its liabilities and commitments in other than the normal course of business at amounts different from those in the accompanying consolidated financial statements. Such adjustments could be material.

New Standards, Interpretations, and Amendments Adopted by the Company

IFRS 3 Business Combinations

This amendment is applied prospectively and clarifies that all contingent consideration arrangements classified as liabilities (or assets) arising from a business combination should be subsequently measured at fair value through profit or loss whether or not they fall within the scope of IFRS 9 (or IAS 39, as applicable). This policy became effective for annual periods starting on or after July 1, 2014.

The adoption of this amendment to IFRS 3 did not have any material impact on the Company's Consolidated Financial Statements.

IFRS 8 Operating Segments

This amendment is applied retrospectively and clarifies that an entity must disclose the judgments made by management in applying the aggregation criteria, including a brief description of operating segments that have been aggregated, and the economic characteristics (e.g., sales and gross margins) used to assess whether the segments are "similar."

The reconciliation of segment assets to total assets is only required to be disclosed if the reconciliation is reported to the chief operating decision maker, similar to the required disclosure for segment liabilities.

This policy became effective for annual periods starting on or after July 1, 2014.

The adoption of IFRS 8 did not have any material impact on the Company's Consolidated Financial Statements.

IAS 16 Property, Plant and Equipment, and IAS 38 Intangible Assets

These amendments are applied retrospectively and clarify in IAS 16 and IAS 38 that an asset may be revalued by reference to observable data on either the gross or the net carrying amount. In addition, the accumulated depreciation or amortisation is the difference between the gross and carrying amounts of the asset. These policies became effective for annual periods starting on after July 1, 2014.

The adoption of IAS 16 and IAS 38 did not have any material impact on the Company's Consolidated Financial Statements.

IAS 24 Related-Party Disclosures

This amendment is applied retrospectively and clarifies that a management entity (an entity that provides key management personnel services) is a related-party subject to the related party disclosures. In addition, an entity that uses a management entity is required to disclose the expenses incurred for management services.

The adoption of this amendment to IAS 24 did not result in any additional disclosures in the Company's Consolidated Financial Statements.

Standards Issued but Not yet Effective

IFRS 9 Impairment of Financial Instruments Under IFRS 9

The impairment requirements in the new standard, IFRS 9 Financial Instruments, are based on an expected credit loss model and replace the IAS 39 Financial Instruments: Recognition and Measurement incurred loss model. The expected credit loss model applies to debt instruments recorded at amortised cost or at fair value through other comprehensive income, such as loans, debt securities and trade receivables, lease receivables, and most loan commitments and financial guarantee contracts. Entities are required to recognise an allowance for either 12-month or lifetime expected credit losses ("**ECL**"s), depending on whether there has been a significant increase in credit risk since initial recognition. The ECL impairment requirements must be adopted with the other IFRS 9 requirements and are effective for annual periods beginning on or after January 1, 2018, with early application permitted.

The Company plans to adopt the new standard at the effective date and is in the process of assessing the impact on its consolidated financial statements.

Amendments to IFRS 11 Joint Arrangements: Accounting for Acquisitions of Interests in Joint Operations

The amendments to IFRS 11 require that a joint operator accounting for the acquisition of an interest in a joint operation, in which the activity of the joint operation constitutes a business, must apply the relevant IFRS 3 Business Combinations principles for business combinations accounting. The amendments also clarify that a previously held interest in a joint operation is not remeasured on the acquisition of an additional interest in the same joint operation while joint control is retained. In addition, a scope exclusion has been added to IFRS 11 to specify that the amendments do not apply when the parties sharing joint control, including the reporting entity, are under common control of the same ultimate controlling party. The amendments apply to both the acquisition of the initial interest in a joint operation, and the acquisition of any additional interests in the same joint operation and are prospectively effective for annual periods beginning on or after January 1, 2016, with early adoption permitted.

These amendments will impact the Company to the extent that it undertakes future transactions of this nature, as this accounting approach differs to that which it would currently apply.

IFRS 15 Revenue and Contracts with Customers

IFRS 15 was issued in May 2014, and establishes a five-step model to account for revenue arising from contracts with customers. Under IFRS 15, revenue is recognised at an amount that reflects the consideration to which an entity expects to be entitled in exchange for transferring goods or services to a customer. The new revenue standard will supersede all current revenue recognition requirements under IFRS. Either a full or modified retrospective application is required for annual periods beginning on or after January 1, 2018. Early adoption is permitted.

The Company plans to adopt the new standard at the effective date and is in the process of assessing the impact on its consolidated financial statements.

IFRS 16 Leases

On January 13, 2016, the IASB issued IFRS 16 which supersedes existing standards and interpretations under IAS 17. IFRS 16 requires all leases to be reported on an entity’s balance sheet and will provide greater transparency on companies’ lease assets and liabilities. The new standard will apply for annual periods beginning on or after January 1, 2019; earlier application is permitted provided the entity has also adopted IFRS 15.

The Company plans to adopt the new standard at the effective date and is in the process of assessing the impact on its consolidated financial statements.

Amendments to IAS 1 Disclosure Initiative

The amendments to IAS 1 clarify, rather than significantly change, existing IAS 1 requirements. The amendments clarify:

- The materiality requirements in IAS 1.
- That specific line items in the statement(s) of profit or loss, OCI and the statement of financial position may be disaggregated.
- That entities have flexibility as to the order in which they present the notes to financial statements.
- That the share of OCI of associates and joint ventures accounted for using the equity method must be presented in aggregate as a single line item, and classified between those items that will or will not be subsequently reclassified to profit or loss.

Furthermore, the amendments clarify the requirements that apply when additional subtotals are presented in the statement of financial position and the statement(s) of profit or loss and other comprehensive income. These amendments are effective for annual periods beginning on or after January 1, 2016, with early adoption permitted.

The Company is in the process of assessing the impact of these amendments to its consolidated financial statements.

11 Internal Control over Financial Reporting and Disclosure Controls and Procedures

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

The Company has established a continuous control testing process with an independent auditor throughout the year. The testing process adds value to our compliance program by:

- Performing process risk assessment identifying high risk and establishing mitigation plans.
- Optimizing key controls and reviewing and updating risk control matrices to all company processes.
- Increasing reliance on entity-level and automated application controls.
- Identifying best practices and process improvement opportunities.

During the fourth quarter of 2015, 278 controls were tested over the 604 total optimized controls the Company has implemented. From this evaluation, the Company concluded that there are no material weaknesses or significant deficiencies in the design or effectiveness of ICFR as at December 31, 2015.

The Company's ICFR 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 ICFR 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.
- 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 are prevented or detected on a timely basis.
- Providing reasonable assurance to access and process information in the system through a continous automated monitoring control process.

The Company's ICFR 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.

In the quarter ended December 31, 2015, there was no change in the Company's ICFR that has materially affected, or is reasonably likely to materially affect, the Company's ICFR.

The Company's DC&P is designed to provide reasonable assurance that:

a) Material information relating to the Company is made known to the Company's certifying officers by others, particularly during the period in which the annual filings are being prepared; and
b) Information required to be disclosed by the Company in its annual filings, interim filings and other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation.

Based on the Company's evaluation carried out to assess the effectiveness of the Company's DC&P, the Company concluded that the DC&P were designed and operated effectively as at December 31, 2015.

12 Further Disclosures

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 2014, 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 2014, the Company initiated the delivery of the additional PAP production from the Quifa SW field to Ecopetrol. In addition, during the second half of 2014, 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 beginning at the end of 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, 2014, the exploitation area of the Carrizales field reached five million barrels in 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 the 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

The Company has certain exploration contracts acquired through business acquisitions where there existed outstanding disagreements with the Agencia Nacional de Hidrocarburos (National Hydrocarbon Agency or "**ANH**" of Colombia), relating to the interpretation of the high-price participation clause. These contracts require high-price participation payments to the ANH once an exploitation area within a contracted area has cumulatively produced five million or more barrels of oil. The disagreement involves whether the exploitation areas under these contracts should be determined individually or combined with other exploration 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 ANH high-price participation. One of these contracts is the Corcel Block, which was acquired as part of the Petrominerales acquisition and 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. As at December 31, 2015, the amount under arbitration is approximately $194 million, plus related interest of $37 million.

The Company also disagrees with the interest rate that the ANH has used in calculating the interest cost. The Company asserts that since the high-price participation is denominated in the U.S. dollar, the contract requires the interest rate to be three-month LIBOR + 4%, whereas the ANH has applied the highest legally authorized interest rate on Colombian peso liabilities, which is over 20%. An amount under discussion with the ANH for another contract is approximately $99 million plus interest.

The Company and the ANH are currently in discussion to further understand the differences in interpretation of these exploration contracts. 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, although 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

During the fourth quarter of 2015, the Company obtained three authorizations from the Autoridad Nacional de Licencias Ambientales ("**ANLA**") and one from by the local environmental authority ("**Cormacarena**") as follows:

Colombia

On October 2, 2015, with Resolucion 1231, the ANLA granted the global environmental licences for Quifa NW located in the Quifa Association Contract. This will allow the Company to develop exploitation activities in this area.

On November 9, 2015, with Resolucion 1426, the ANLA granted the global environmental license for the Curito field located in the Casanare Este E&P Contract.

On December 10, 2015, with Resolucion 1595, the ANLA granted the amendment to the global environmental license of the Guama field.

In addition, in December 2015, PROAGROLLANOS, an entity unrelated to the Company, obtained the environmental permit needed to use treated wastewater from the Rubiales field. With this permit the Company can deliver up to 1,500,000 water barrels per day from the Rubiales field to be used in agribusiness activities.

13 Additional Financial Measures

This report contains the following financial terms that are not considered in IFRS: Adjusted EBITDA, Net (Loss) Earnings from Operations, and Funds Flow from Operations. These non-IFRS measures do not have any standardized meaning, and therefore are unlikely to be comparable 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.

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 eliminates 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:

	Year Ended December 31		Three Months Ended December 31	
(in thousands of US$)	2015	2014	2015	2014
Net loss [1]	**$ (5,461,859)**	**$ (1,309,625)**	**$ (3,895,908)**	**$ (1,660,876)**
Adjustments to net loss				
Income tax (recovery) expense	(466,514)	188,736	(358,669)	(179,597)
Foreign exchange loss	134,477	63,211	21,396	52,239
Finance cost	434,846	261,300	205,917	73,738
(Gain) loss on risk management contracts	(129,474)	7,985	(61,553)	17,315
(Gain) loss of equity-accounted investees	(21,537)	33,325	(7,875)	49,012
Other expenses (income)	80,992	(12,815)	27,914	10,018
Share-based compensation	(1,564)	10,243	(6,245)	(20,028)
Equity tax	39,149	-	-	-
Severance and related costs [2]	7,695	-	7,695	-
Loss attributable to non-controlling interest	(21,112)	(25,210)	(20,265)	(23,855)
Depletion, depreciation and amortization	1,529,016	1,641,577	380,281	475,952
Impairment and exploration expenses	4,907,209	1,625,358	3,890,229	1,625,358
Adjusted EBITDA	**$ 1,031,324**	**$ 2,484,085**	**$ 182,917**	**$ 419,276**

1. Net loss attributable to equity holders of the parent.
2. Estimated severance and related costs that are expected to be incurred in 2016, primarily related to the expiry of the Rubiales field.

Funds Flow from Operations

	Year Ended December 31		Three Months Ended December 31	
(in thousands of US$)	2015	2014	2015	2014
Cash flow from operating activities	$ 220,080	$ 2,104,299	$ 81,684	$ 616,749
Changes in non-cash working capital	432,575	(83,058)	(114,407)	(206,980)
Deferred revenue net proceeds	(74,155)	-	75,000	-
Funds flow from operations	**$ 578,500**	**$ 2,021,241**	**$ 42,277**	**$ 409,769**

Net Loss from Operations

(in thousands of US$)	Year Ended December 31 2015	Year Ended December 31 2014	Three Months Ended December 31 2015	Three Months Ended December 31 2014
Net loss [(1)]	$ (5,461,859)	$ (1,309,625)	$ (3,895,908)	$ (1,660,876)
Finance costs	434,846	261,300	205,917	73,738
(Gain) loss of equity-accounted investees	(21,537)	33,325	(7,875)	49,012
Equity tax	39,149	-	-	-
Foreign exchange loss	134,477	63,211	21,396	52,239
(Gain) loss on risk management contracts	(129,474)	7,985	(61,553)	17,315
Other expenses (income)	80,992	(12,815)	27,914	10,018
Income tax (recovery) expense	(466,514)	188,736	(358,669)	(179,597)
Loss attributable to non-controlling interest	(21,112)	(25,210)	(20,265)	(23,855)
Net loss from operations	**$ (5,411,032)**	**$ (793,093)**	**$ (4,089,043)**	**$ (1,662,006)**

1. Net loss attributable to equity holders of the parent.

Oil and Gas Metrics

This report contains metrics commonly used in the oil and natural gas industry, such as operating net backs, operating costs and average realized price. These terms do not have a standardized meaning and may not be comparable to similar measures presented by other companies, and therefore should not be used to make comparisons. Operating net backs have been calculated by subtracting production costs, transportation costs, diluent costs, other costs, royalties and overlift/underlift costs from the realized oil and natural gas sales price per barrel of oil equivalent and may be used to determine the profit realized by the Company for each barrel of oil equivalent sold. Operating costs have been calculated by adding production costs, transportation costs and diluent costs, and may be used to determine the profitability of the Company. Average realized price is calculated by dividing the average daily volume sold by the revenue received for such sales over the course of a year and may be used to determine the average price received by the Company for each barrel of oil equivalent sold. Management uses these oil and gas metrics for its own performance measurement and to provide stakeholders with measures to compare the Company's operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this report, should not be relied upon for investment or other purposes.

14 Sustainability Policies

On December 1, 2015, the Company held its annual Sustainability Board Committee meeting and it agreed on a sustainability strategy tailor-made to contribute to the Company´s objectives in a low oil price scenario. During 2016, the Company will focus on: (a) using the social investment budget efficiently in alliance with local public and private actors in order to increase impact and guarantee sustainability. Changes in budgets have been, and will be, made without risking violations of the standards we are committed to, as well as guarding production levels; (b) continuing to engage with stakeholders transparently and in a timely fashion, informing them about changes and activities in order to continue guaranteeing a positive buy in of the Company's operations. The Company is committed to uphold sustainability commitments and standards throughout the business, recognizing that market conditions may test its capacities but should never change its philosophy to create shared value alongside its surroundings.

In addition to the information included in the Annual Information Form, the Company provides the following updates:

Gender Equality Recognition

In line with our Gender Equality Declaration, for the past two years the Company has participated in the Equipares gender equality seal process granted by the UNPD and the Colombian Ministry of Labor. The process consists of helping companies overcome barriers of discrimination that are ingrained in its practices in order to guarantee that men and women obtain equal opportunities. Last November, Pacific was awarded with the "Commitment to Equality" recognition by these organizations, an important milestone in its effort to obtain the seal.

Advances in Operations in Block 192

In response to the growing interest of the Company´s investors and analysts, the Company reiterates its commitment to pursuing free, prior, and informed consent with the autonomous indigenous organizations that surround the block, as it has applied in the rest of its operations, both in Peru and Colombia. To date, operations have been carried out in a calm and concerted environment. Agreements on environmental measures and labor opportunities as well as social investment have been reached, mainly in health and education. Additional information will be provided in the 2015 Annual and Sustainability Report.

Extractive Industries Transparency Initiative ("EITI") Report in Colombia

On October 26, 2015, the Company signed a document of adherence with the Colombian Ministry of Energy and Mines, to participate in the first country report, one of the requisites in order to be ratified as a member country. With this report Colombia aims to create an efficient social monitoring mechanism and help guarantee that payments made to the government by extractive companies are truly contributing to building more developed communities and thereby more favourable business conditions. In line with its commitment with EITI global, the Company will be publishing all payments for the year 2015 in its Annual and Sustainability Report.

Recognitions

For the third year in a row, the Company was included amongst the members of the North American Dow Jones Sustainability Index ("**DJSI**"). With this recognition, the Company reaffirms its position as an industry leader in sustainability along with a select group of nine companies that were chosen from a total of 34 that participated.

After the certification of the Rubiales and Quifa fields under EO100 standard in 2014, the Company underwent the annual recertification process in the months of July and August 2015, with the audit company Deloitte. During the process, EO staff conducted interviews and revisions in order to guarantee that the Company was still under compliance with all standards provisions. The Company´s fields are still at 100% compliance for target 1 and under bronze leadership rating. After the termination of the Rubiales contract on June 30, 2016, the Company will only work on recertifying the Quifa field.

15 Risks and Uncertainties

The business, operations, and earnings of the Company could be impacted by the occurrence of risks and uncertainties of all kinds, including financial, operational, technological, regulatory, and political, that might affect the oil and gas industry generally, or the Company specifically.

These risks and uncertainties include the fact that, despite a number of cost reduction initiatives that have been implemented by the Company, at current oil prices the Company will likely need new financing to fund its interest payments and debt repayments as they come due, and possibly operating cash needs. The Company is currently in default of the payment of interest on two series of its Senior Notes and in breach of certain covenants under its revolving and bank credit facilities, although forbearance agreements are in place with certain holders of such senior notes and with the lenders under such credit facilities that remain in effect (subject to certain conditions) until March 31, 2016. The Company has also breached several minimum credit rating covenants in certain operational agreements it has entered into, as a result of downgrades of the Company's credit ratings during 2015, although waivers relating to these covenants have been granted for various limited periods. There can be no certainty as to the ability of the Company to successfully restructure its long-term debts, amend the applicable operating agreements to eliminate the credit rating covenants, and obtain new financing should low crude prices persist, and accordingly, there is a material uncertainty that may cast doubt on the Company's ability to continue as a going concern.

The Company intends to fund its anticipated cash requirements through the end of 2016 primarily through cash on hand and cash flows from operations, although these sources may not be sufficient to fund such requirements.

To continue as a going concern, the Company must generate sufficient operating cash flows, secure additional capital or otherwise pursue a strategic restructuring, refinancing or other transactions to provide it with additional liquidity. The Company cannot provide any assurance that any of these actions can be effected on a timely basis, on satisfactory terms or maintained once initiated. If they are not, the Company's liquidity and results of operations will be materially adversely affected and the Company would not be able to continue as a going concern. The urgency of the Company's liquidity constraints may require the Company to pursue such transactions at an inopportune time. Moreover, the Company's ability to successfully implement, and the cost of, any such transactions will depend on numerous factors, including:

- demand and prices for natural gas and oil;
- general economic conditions;
- the strength of the credit and capital markets;
- the Company's ability to successfully execute its operational strategies, and its operating and financial performance;
- the Company's ability to comply with the covenants in its debt instruments;
- the Company's ability to renew the forbearance or extension agreements with respect to the Credit Facilities and the 2109 Senior Notes and 2025 Senior Notes, as applicable;
- the Company's ability to comply with its operating agreements;
- the Company's ability to maintain relationships with its suppliers, customers, employees, stockholders and other third parties; and
- market uncertainty in connection with the Company's ability to continue as a going concern as well as investor confidence in the Company.

If the Company is unable to continue as a going concern, it would likely need to seek relief under applicable bankruptcy and insolvency legislation, which may negatively affect the price and volatility of the Company's common shares and other securities of the Company and any investment in such shares or securities could suffer a significant decline or total loss in value.

Other material risk factors include, but are not limited to:

- volatility in market prices for oil and natural gas;
- a continued depressed oil price environment with a potential of further decline;
- default under the credit facilities and/or senior notes due to a breach of covenants therein;
- early termination of one or more of the Lender Forbearance Agreements and/or the Noteholder Extension Agreement;
- amounts becoming due and payable under the credit facilities or senior notes, notwithstanding the entering into of the Lender Forbearance Agreements and the Extension Agreement, whether through the actions of holders of the 2019 Senior Notes and 2025 Senior Notes or the trustee under each respective indenture or otherwise;
- the impact of events of defaults in respect of the credit facilities, 2019 Senior Notes and 2025 Senior Notes on other material contracts of the Company, including but not limited to, cross-defaults resulting in acceleration of amounts payable thereunder or the termination of such agreements;
- failure of the Company to reach an agreement with its creditors to restructure the Company's capital structure;
- failure to satisfy any terms or conditions of any agreement with its creditors on a proposed restructuring;
- any negative impact on the Company's current operations as a result of any proposed restructuring or failure to reach an agreement with the creditors thereon;
- failure to satisfy the terms and conditions of any one of the Company's waiver agreements with applicable creditors or any other waiver, failure to obtain further extensions of any such waivers, or failure to obtain waivers of other covenants, if and when required;
- the terms of any waivers, including the impact on the Company of any restrictions imposed upon it in connection with any waiver;
- failure to obtain additional financial resources to avoid the need to seek relief under the bankruptcy and insolvency laws in one or more of Canada, the United States, Colombia and/or other jurisdictions (or avoid an involuntary petition for bankruptcy relief or similar creditor action filed against the Company);
- investors' perceptions of the Company's prospects and the prospects of the oil and gas industry in Colombia and the other countries where the Company operates and/or has investments;
- expectations regarding the Company's ability to raise capital and to continually add to reserves through acquisitions and development;
- inability to continue meeting the listing requirements of the exchanges on which the Company's securities are listed;
- the value of the Company's equity securities being reduced to zero as a result of an insolvency filing and that such proceedings may ultimately result in the cancellation of the Company's equity securities;
- the effect of ratings downgrades on the Company's business and operations;
- political developments in Colombia, Guatemala, Peru, Brazil, Guyana and Mexico;
- liabilities inherent in oil and gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions and/or past integration problems;
- geological, technical, drilling and processing problems;
- fluctuations in foreign exchange or interest rates and stock market volatility;
- delays in obtaining required environmental and other licences;
- uncertainty of estimates of capital and operating costs, production estimates and estimated economic return;
- the possibility that actual circumstances will differ from estimates and assumptions;
- uncertainties relating to the availability and costs of financing needed in the future; and
- changes in income tax laws or changes in tax laws, accounting principles and incentive programs relating to the oil and gas industry.

The Company's Annual Information Form, filed on March 18, 2016, and available at www.sedar.com, contains a complete discussion of the risks and uncertainties that could have an effect on the business and operations of the Company. Readers are urged to read such discussion in its entirety.

16 Advisories

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, boe has been expressed 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 in Peru. For all natural gas reserves in Colombia, boes 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, boes have been expressed using the Canadian conversion standard of 6.0 Mcf: 1 bbl. If a conversion standard of 6.0 Mcf: 1 bbl were used for all 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.

Translation

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

17 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
BSW	Basic sediments and water
Btu	British thermal units
Bwd	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
GOR	Gas – Oil Ratio
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
MDRT	Measure depth rotary table
MDT	Modular formation dynamics test
MWD	Measurement while drilling
MMcf/d	Million cubic feet per day
MD	Measured depth
MMbbl	Million barrels
MMbbl/d	Million barrels of oil per day
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
Scf	Standard cubic feet
Stb/d	Standard barrels per day
Tcf	Trillion cubic feet
TD	Total depth
TVDSS	True vertical depth below sea level
USGC	US Gulf Coast
WTI	West Texas Intermediate index