MANAGEMENT DISCUSSION & ANALYSIS

March 14, 2017
For the year ended December 31, 2016

CONTENTS

Legal Notice – Forward-Looking Information and Statements

Certain statements in this Management's 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," "is expected," "anticipates," "does not anticipate," "plans," "planned," "estimates," "estimated," "projects," "projected," "forecasts," "forecasted," "believes," "intends," "likely," "possible," "probable," "scheduled," "positioned," "goal," or "objective." In addition, forward-looking statements often 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 that may cause the actual levels of production, costs, and results to be materially different from the estimated levels expressed or implied by such forward-looking statements. The Company believes the expectations reflected in these forward-looking statements are reasonable, but the Company cannot assure 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 oil and gas that will be encountered only 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 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 ultimate recovery.

For more information, please see the Company's Annual Information Form dated March 14, 2017, 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 Consolidated Financial Statements and related notes for the years ended December 31, 2016 and 2015. 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 ended December 31, 2016 and 2015, 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 18.

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 and on the Company's website at www.pacific.energy. Information contained in or otherwise accessible through the Company's website does not form a part of this MD&A and is not incorporated by reference into this MD&A.

1. Message to the Shareholders

This was a year of significant change for Pacific, financially, operationally and culturally. On November 2, 2016, the Company successfully completed a comprehensive financial restructuring which was a critical first step to position the Company for future success. The Company emerged from its restructuring with a new Board of Directors, management team and a plan focused on capital discipline and value maximization.

On February 20, 2017, I assumed my position at Pacific Exploration & Production as Chief Executive Officer (CEO). I have over 40 years of oil and gas industry experience, 21 of which have been with operations at the international level. As you are likely aware, I was most recently a director of Pacific, appointed to the new Board as part of the successful recapitalization and restructuring of the Company. Concurrent with my appointment as CEO, I stepped down from my role as a director; the Board is evaluating independent director candidates with skills, experience and capabilities that would be beneficial to the Company and its shareholders.

The Company continues to operate fields and facilities to maximize production while minimizing capital expenditures. During 2016, net production after royalties and internal consumption totaled 103,352 boe/d, representing a decrease of 51,120 boe/d (33%) from the average net production of 154,472 boe/d reported in the previous year. This reduction was attributable to the expiration of the Rubiales and Piriri fields, lower drilling activity as a result of reduced capital expenditures during the Company's restructuring process and operational issues related to water disposal capacity.

The Company was able to deliver stable results through the end of 2016 and is positioned to perform well in 2017. While 2016 results were primarily impacted by the expiration of the Rubiales and Piriri fields mid-year and the difficulties of running the business while in a restructuring process, Pacific is very pleased with the amount of progress made to reduce costs, rationalize the Company's portfolio and allow for a dedicated focus on high return opportunities on core E&P assets in Colombia and Peru. Pacific has a vast opportunity to find future growth and with capital discipline and operational rigor will take every step to create long-term value for all shareholders.

Revenue decreased to $1,412 million from $2,825 million in 2015, due to the nearly 16% year-on-year decline in realized crude oil prices, the expiration of the Rubiales-Piriri contract and $138 million lower realized gains from oil hedging contracts compared with 2015. The Company has implemented a program entering into several oil price risk management contracts to hedge against oil price volatility through 2017. Operating EBITDA for 2016 was $445 million and $44 million for the fourth quarter of 2016, lower compared to $1,166 million in 2015 and $235 million in the fourth quarter of 2015 (for a discussion on Operating EBITDA and other non-GAAP measures, please refer to page 20). General and Administrative costs (excluding restructuring and severance expenses) decreased to $145 million in 2016 from $203 million in 2015 as the Company continues to reduce G&A and all non-essential spending activities.

During the second half of 2016, the Company successfully negotiated the divestment of its non-core assets in Brazil. In addition, the Company continues to negotiate field commitments to focus on high impact development drilling, while reviewing the broad set of upstream and midstream assets within the Company's portfolio with an emphasis on value-maximizing initiatives.

Pacific is off to a great start in 2017, a critical year as the Company shifts focus and resources towards sustainable production through development drilling and growth through low-risk exploration. The Company continues to look at ways to maximize the value of non-E&P related assets and reduce overall costs. Pacific's goal is to improve margins and drive higher returns for invested capital so that the Company's long-term growth can be self-sustaining.

"Barry Larson"
Chief Executive Officer

2. Results for the Year Ended December 31, 2016

Financial and Operating Summary

(in thousands of US$ except per share amount or as noted)	Year Ended December 31 2016	2015	Three Months Ended December 31 2016	2015
Operating activities				
Average sales volumes (boe/d)	95,496	159,113	69,653	171,928
Average oil and gas sales (boe/d)	94,716	151,806	67,470	171,039
Oil sales (bbl/d)	86,339	138,913	60,713	145,890
Gas sales (boe/d)	8,372	9,211	6,738	10,541
Overlift (boe/d)	5	3,682	19	14,608
Average trading sales (bbl/d)	780	7,307	2,183	889
Average net production (boe/d)	103,532	154,472	69,432	159,831
Average net production oil (bbl/d)	94,769	145,245	62,229	149,368
Average net production gas (boe/d)	8,763	9,227	7,203	10,463
Average net production (boe/d) (excluding Rubiales field)	79,671	99,759	69,432	105,118
Combined price ($/boe)	40.36	48.51	41.92	41.22
Realized oil and gas price ($/boe)	35.97	43.28	43.44	32.75
Realized hedging gain (loss) ($/boe)	4.39	5.23	(1.52)	8.47
Operating cost ($/boe)	(22.78)	(22.48)	(27.98)	(22.01)
Operating netback crude oil and gas ($/boe) (1)	17.58	26.03	13.94	19.21
Consolidated netback ($/boe) (1)	16.49	24.78	13.30	17.41
Cash netback ($/boe)	9.31	16.22	5.46	9.70
Capital expenditures	161,462	725,512	64,248	160,154
Total Certified 2P Reserves net after royalties (MMboe)	170.7	290.8	170.7	290.8
Financials				
Total sales ($)	1,411,711	2,824,546	269,772	651,970
Net crude oil and gas sales and other income	1,399,064	2,653,279	260,123	613,818
Trading	12,591	136,459	9,593	3,344
Overlift	56	34,808	56	34,808
Net income (loss)(2)	2,448,523	(5,461,859)	4,025,194	(3,895,908)
Per share - basic ($) (3)	48.97	(1,733,923)	80.50	(1,236,713)
Operating EBITDA(1)	444,637	1,165,758	44,275	224,911
Operating EBITDA margin (Operating EBITDA/revenues)	31%	37%	16%	34%
Consolidated EBITDA(1)	253,619	1,111,566	(1,967)	257,584
Consolidated EBITDA margin (Consolidated EBITDA/revenues)	18%	39%	(1)%	40%
Total Assets ($)	2,741,719	3,986,121	2,741,719	3,986,121
Total Equity (Deficit) ($)	1,495,770	(3,099,376)	1,495,770	(3,099,376)
Debt and obligations under finance lease ($)	272,942	5,413,857	272,942	5,413,857

1. *Refer to non-GAAP measures on page 20.*
2. *Net income (loss) attributable to equity holders of the parent.*
3. *The basic weighted average numbers of common shares for the years ended December 31, 2016 and 2015 were 50,002,363 and 3,150, respectively.*

Results

Operational

- For 2016, the Company's average daily net production after royalties was 103,532 boe/d, 33% lower compared with the previous year. The average daily net production after royalties in the fourth quarter 2016 decreased to 69,432 boe/d, lower by 57% as compared to the same period of 2015. The decrease was mainly attributable to the expiration of the Rubiales-Piriri contract on June 30, 2016 and lower production in other fields due to lower drilling activity and operational issues related to water disposal capacity.
- During 2016, the combined oil and gas operating cost was $22.78/boe, slightly higher compared with $22.48/boe for 2015 due to higher production and transportation costs but ameliorated by lower dilution costs. Average production cost was higher due to lower volume produced, and transportation cost rose as a result of slightly higher tariffs on the main pipelines. Dilution cost was lower because of the Company's strategy to utilize alternative dilution arrangements."
- In 2016 the Company entered into several operational collaborative agreements with third parties in Colombia which resulted in savings in dilution cost and fuel cost. Additionally as a result of negotiation efforts, an increase in the regulated transportation tariffs was delayed until the end of 2016. At the same time, pipeline tariff schemes were adapted to the low oil price environment.
- The Company continues to negotiate field commitments to focus on high-impact development drilling. On March 17, 2016, the Agencia Nacional de Hidrocarburos ("**ANH**") approved the transfer of $38 million in exploration commitments from Las Aguilas, Castor, LL-59, LL-15 and CPE-1 blocks to the Casanare Este, Mapache, Guatiquia, Guama LL-83 and Rio Ariari blocks. On November 22, 2016, the ANH approved a second investment transfer totalling $19 million from the CPO 14, Sabanero, LL-19 and Topoyaco blocks to the LL-25 Block.
- The Company successfully completed the divestment of all our non-core assets in Brazil including:
    - On September 27, 2016, the Company reached an agreement with partners Karoon Gas Australia Ltd. and Karoon Petroleo e Gas Ltda., to sell the Company's 35% working interest in the joint concession agreements in Brazil for $15.5 million in cash consideration. The transaction was approved by the Brazilian regulator on January 30, 2017.
    - On October 14, 2016, the Company also reached an agreement with partner Queiroz Galvão Exploração e Produção S.A. to withdraw from joint working interests; the Company will pay $10 million in exchange for release from future work commitments in the aggregate amount of $76.3 million. The Queiroz transaction was approved by the Brazilian regulator on March 13, 2017, and is expected to be fully consummated shortly subject to the amendment of the concession agreements. Also as a result of the transaction, the Company will be released from approximately $41 million of letter of credit requirements.
- On November 30, 2016 the Company and CEPSA ("**Compañía Española de Petróleos**") Peru entered into an agreement, whereby CEPSA agreed to acquire our 30% participating interest in the Licence Agreement for Block 131, in which CEPSA Peru is the operator. The sale price is $17.8 million with adjustment based on future cash flow from the block; the transaction is subject to Peruvian regulatory approval.
- On March 10, 2017, the Company and Amerisur Exploración Colombia Limitada ("**AMERISUR**") entered into four (4) farm-out agreements, whereby AMERISUR agreed to acquire: (i) our 60% participating interest in the License Agreement for Block PUT-9; (ii) our 50.5% participating interest in the License Agreement for Block Tacacho; (iii) our 58% participating interest in the License Agreement for Block Mecaya; and (iv) our 100% participating interest in the License Agreement for Block Terecay. The total transaction price is $4.9 million, plus a royalty calculated and payable on a monthly basis equal 2% of all the hydrocarbons produced on the block Terecay, and a royalty calculated and payable on a monthly basis equal 1.2% of all the hydrocarbons produced on the block PUT-9. Each farm-out agreement is subject to Colombian regulatory approval.

Financial

- Revenue decreased to $1,412 million from $2,825 million in 2015, and for the fourth quarter of 2016 to $270 million from $652 million for the same period in 2015. The decreases were due to the nearly 16% year-on-year decline in realized crude oil prices, the expiration of the Rubiales-Piriri contract and $138 million lower realized gains from oil hedging contracts compared with 2015. Total volume of oil and gas sales (including trading) for 2016 averaged 95,496 boe/d, 40% lower than the 159,113 boe/d in 2015, mainly due to the expiration of the Rubiales-Piriri fields in June 2016 and the lower production in other fields.
- Combined oil and gas operating netback for 2016 was $17.58/boe, 32% lower than the $26.03/boe in 2015 and mainly attributable to the decline in market prices for crude oil. The Company's average sales price per barrel of crude oil and natural gas was $40.36/boe in 2016, down from $48.51/boe in 2015. Netback in the fourth quarter of 2016 decreased to $13.94/boe from $19.21/boe in the same period of 2015 due to lower volumes sold.
- In 2016, combined oil and gas operating cost was $22.78/boe, higher compared with $22.48/boe for 2015. The increase was mainly due to lower volumes after the expiration of Rubiales which, as a mature field, had lower costs than other fields. In addition, transportation costs increased due to lower transported volumes and the fixed rates of the Company's ship-or-pay agreements.
- Operating EBITDA was $445 million for 2016 and $44 million for the fourth quarter of 2016, lower compared to $1,166 million in 2015 and $235 million in the fourth quarter of 2015, primarily due to the expiration of Rubiales-Piriri fields in June 2016 and lower realized prices, including hedging gains and losses.
- General and Administrative ("**G&A**") costs (excluding restructuring and severance expenses) decreased to $145 million in 2016 and $40 million in the fourth quarter of 2016 from $203 million in 2015 and $55 million in the fourth quarter of 2015; the Company continues to reduce G&A and all non-essential spending activities.
- Net Income for 2016 was $2,449 million, largely due to non-cash items and one-time items, including the recognition of a net gain of $3.6 billion on the cancellation of the debt held by the Affected Creditors in exchange for the issuance of new common shares and $155 million in costs related to the Restructuring Transaction.
- The Company recorded net impairment charges of $477 million for 2016, which included impairment losses of $1,113.6 million during the first three quarters and a reversal of impairment of $636.9 million in the fourth quarter of the year. Impairment tests were performed at the end of 2016 based on the reserves certified by external evaluators as of December 31, 2016.
- Total capital expenditures decreased to $161 million in 2016 compared with $726 million in 2015 as the Company remains focused on deploying capital on high-impact programs.
- On March 13, 2017 the Colombian Insolvency Judge issued a decision to terminate the proceedings under Ley 1116 of 2006. Consequently, the Company will initiate the processes to lift all liens imposed by the mentioned judge, including the remaining $23.7 million held in the trust account on behalf of Colombian trade creditors at the time.

Successful Completion of CCAA Restructuring

On April 19, 2016, with the support of certain holders of its senior unsecured notes and lenders under its credit facilities, the Company entered into an agreement with The Catalyst Capital Group Inc. ("**Catalyst**") with respect to a comprehensive financial restructuring ("**Restructuring Transaction**"). Under the terms of the agreement, the claims of the senior noteholders, the lenders under the credit facilities, and certain other third parties (collectively the "**Affected Creditors**") were exchanged for new common shares of the reorganized company. In addition, Catalyst and certain Affected Creditors provided new cash financing to recapitalize the Company.

On April 27, 2016, the Company, including certain direct and indirect subsidiaries, obtained an Initial Order from the Superior Court of Justice in Ontario under the Companies' Creditors Arrangement Act ("**CCAA**") with respect to the Restructuring Transaction.

On November 2, 2016, the Company successfully completed the Restructuring Transaction upon approval of the CCAA plan of arrangement by the Superior Court of Justice in Ontario and through appropriate proceedings in Colombia and in the United States. The Restructuring Transaction included the following key features:

- The Company's operations continued as normal throughout the period of restructuring and obligations to the Company's suppliers, trade partners and contractors continued to be met.

- Certain of the Company's Affected Creditors (the "**Funding Creditors**") and Catalyst jointly provided $500 million of debtor-in-possession financing (the "**DIP Financing**") less an original issue discount of 4%. The DIP Financing was secured by assets of the Company and its subsidiaries. Pursuant to the DIP Financing, Catalyst provided $240 million (after taking into account the original issue discount) for the purchase of notes (the "**Plan Sponsor DIP Notes**"); the Funding Creditors provided the other $240 million for the purchase of notes (the "**Creditor DIP Notes**") and warrants with a nominal exercise price (the "**Warrants**").
- Upon implementation of the Restructuring Transaction, claims by the Affected Creditors in the amount of approximately $5.7 billion (including principal and accrued interest) were exchanged for approximately 58.2% of the common shares of the reorganized company.
- The Affected Creditors also had the opportunity to receive cash in lieu of some or all of the common shares of the reorganized Company that they would otherwise be entitled to receive (the "**Cash Elections**"). Approximately 1.5% of the common shares of the reorganized company were acquired by Catalyst as Plan Sponsor, and another 0.35% acquired by certain of the Company's Affected Creditors through subscriptions to fund the Cash Elections.
- Upon implementation of the Restructuring Transaction:
  - The Plan Sponsor DIP Notes were exchanged for 29.3% of the total newly issued common shares. Catalyst as Plan Sponsor acquired an additional 1.5% of the common shares through the Cash Elections for a total interest of 30.8% of the common shares of the reorganized company;
  - The Creditor DIP Notes were amended and restated as five-year secured notes (the "**Senior Secured Notes**"). The Senior Secured Notes accrue interest at a rate equal to 10%. The Funding Creditors also exercised the Warrants in exchange for 12.5% of the newly issued common shares; and
  - All the previously issued and outstanding common shares of the Company, together with the common shares issued as part of the Restructuring Transaction, were consolidated on the basis of 100,000 pre-consolidation shares to one post-consolidation share. As a result, upon completion of the Restructuring Transaction, there were 50,002,363 fully diluted common shares in the reorganized Company, allocated as follows:

Shareholder	**Percentage**
Catalyst [(1)]	30.8%
Affected Creditors	69.2%

(1) Includes shares Catalyst received through subscriptions to fund the Cash Elections.

  - The Company's common shares that were issued and outstanding prior to the implementation of the Restructuring Transaction were extensively diluted as a result of the 100,000-to-1 consolidation.

The Restructuring Transaction substantially changed the capital structure of the Company, as set out below:

	Principal outstanding as at	
	December 31, 2016	**Inmediately before restructuring**
Credit facilities	$ -	$ 1,215,440
Senior unsecured notes	-	4,104,200
Catalyst & Creditor DIP Notes	-	500,000
Exit Notes (due 2021)	250,000	-
Total loans and borrowings	$ 250,000	$ 5,819,640
Number of common shares outstanding	50,002,363	315,021,198

DIP Cash Collateral Account

On June 22, 2016, in accordance with the Restructuring Transaction, the funds related to the DIP Financing were deposited into a Canadian bank account in the name of the Company and were subject to several conditions, all of which were complied with during the restructuring. Upon completion of the Restructuring Transaction on November 2, 2016, the conditions associated with the DIP Cash Collateral Account were removed and the remaining cash balance was transferred back to the Company's operating accounts.

Colombian Affected Creditors Security

On June 10, 2016, the Superintendencia de Sociedades of Colombia (the "**Superintendencia**") granted an order under Ley 1116 recognizing the CCAA proceedings as the foreign main proceedings for the Restructuring Transaction. The Superintendencia also authorized the granting of security over the Colombian branches in connection with the DIP Financing and resolved that $50 million should be held in trust until the Restructuring Transaction was complete as security for the Colombian Affected Creditors ("**Colombian Affected Creditors Security**").

Upon completion of the Restructuring Transaction on November 2, 2016, the Colombian Affected Creditors Security was released. Consequently, the $50 million held in trust on behalf of Colombian creditors was returned to the Company, which then established a $39 million trust account in favour of Colombian trade creditors that had not yet been paid. The purpose of this Colombian trust account is to secure the amounts owed to the mentioned creditors and to administrate and execute payments, as set out in the payment schedule previously submitted to the Superintendencia. The balance in this trust account as at December 31, 2016 was $28 million and recorded as current restricted cash. The security and restriction over the trust account were subsequently lifted on March 13, 2017, and the Company has initiated the processes to have the remaining balance in the trust account released.

Net Gain on Completion of Restructuring Transaction

Upon completion of the Restructuring Transaction, the claims of the Affected Creditors and the Plan Sponsor DIP Notes were extinguished, and the Warrants held by the Funding Creditors were exercised, in exchanged for newly issued shares of the Company. The net difference between the carrying amounts of the claims of the Affected Creditors, the Plan Sponsor DIP Notes, and the Warrants, and the fair value of the common shares issued, was recorded as a gain.

The fair value of the common shares issued to the Affected Creditors, Catalyst and Warrant holders were estimated using the closing share price of $42.5 (C$57) per share on November 3, 2016, being the day that the Company's common shares resumed trading on the TSX.

	Inmediately before restructuring	Fair value of common shares	Consolidated statements income (loss) impact
Claims of affected creditors	$ 5,498,476	$ 1,237,836	$ 4,260,640
Plan sponsor DIP notes	250,000	624,301	(374,301)
Warrants	-	265,858	(265,858)
Total	$ 5,748,476	$ 2,127,995	$ 3,620,481

Restructuring and Severance Costs

During the year ended December 31, 2016, the Company incurred $154.9 million in costs related to the Restructuring Transaction. These costs were incurred predominantly for the appointment of independent financial and legal advisors, retention bonuses, and severances related to workforce reductions.

	Year ended December 31	
	2016	2015
Restructuring cost	$ 121,608	$ -
Severance	33,247	18,311
Total	$ 154,855	$ 18,311

Principal Properties

	Working interest	Operated	Gross Acres	Net Acres
Colombia Central				
Quifa	60.00%	Operated	265,954	159,572
Guatiquia	100.00%	Operated	14,372	14,372
Cubiro	100.00%	Operated	44,360	44,360
Cravo Viejo	100.00%	Operated	46,839	46,839
Casimena	100.00%	Operated	32,188	32,188
Arrendajo	97.50%	Operated	33,280	32,448
Neiva	56.00%	Non-operated	2,395	1,332
Corcel	100.00%	Operated	25,141	25,141
Cachicamo	100.00%	Operated	28,471	28,471
Canaguaro	87.50%	Operated	6,289	5,503
Dindal - Rio Seco	45.00%	Operated	47,689	21,539
Sabanero	100.00%	Operated	87,540	87,540
Llanos 7	100.00%	Operated	152,674	152,674
Llanos 55	100.00%	Operated	101,466	101,466
Llanos 83	100.00%	Operated	35,755	35,755
Llanos 25	100.00%	Operated	169,805	169,805
Casanare Este	100.00%	Operated	18,476	18,476
Rio Ariari	100.00%	Operated	307,036	307,036
Mapache	100.00%	Operated	55,374	55,374
CPE-6	100.00%	Operated	593,018	593,018
CPO-12	57.00%	Operated	708,765	404,988
CPO-14	63.00%	Operated	517,656	323,535
Abanico	25.00%	Operated	62,560	15,640
Buganvilles	49.00%	Operated	77,754	38,100
Cordillera-24	85.00%	Operated	619,817	526,844
CPO-17 (1)	25.00%	Non-operated	519,663	129,916
Cordillera-15 (1)	50.00%	Non-operated	294,935	147,468
Muisca (1)	50.00%	Non-operated	585,126	292,563
Colombia North				
La Creciente	100.00%	Operated	26,650	26,650
Guama	100.00%	Operated	70,993	70,993
SSJN-3	100.00%	Operated	634,364	634,364
SSJN-7	50.00%	Operated	668,919	334,460
CR-1	60.00%	Operated	307,384	184,431
Cerrito	80.00%	Non-operated	10,166	8,112
Colombia South				
Orito	79.00%	Non-operated	42,492	33,569
Caguan-5	50.00%	Operated	919,321	459,661
Caguan-6	60.00%	Operated	119,048	71,429
Portofino	40.00%	Non-operated	258,676	103,470
Tinigua	50.00%	Non-operated	105,467	52,734
Terecay (2)	100.00%	Operated	586,626	586,626
Tacacho (2)	51.00%	Operated	589,008	297,449
Putumayo-9 (2)	60.00%	Operated	121,452	72,871
Mecaya (2)	58.00%	Operated	74,127	42,993
Peru				
Block Z1	49.00%	Operated	554,443	271,677
Lot 131	30.00%	Non-operated	1,923,476	577,043
Lot 126	100.00%	Operated	1,048,762	1,048,762
Lot 116	50.00%	Operated	1,628,126	814,063
Lot 135	100.00%	Operated	2,521,439	2,521,439
Lot 192	100.00%	Operated	1,266,037	1,266,037

1. *Includes investment on Maurel & Prom Colombia B.V. fields.*
2. *Blocks held for sale please refer to Amerisur operational highlight page 3.*

3. Financial and Operational Results

Netbacks

The Company's netbacks are summarized below. For a discussion on the definitions of and how the Company uses Operating Netback, Consolidated Netback, and Cash Netback, refer to Non-GAAP Measures.

	Year Ended December 31		Three Months Ended December 31		For reconciliation to IFRS figures, see section:
	2016	**2015**	**2016**	**2015**	
Average daily D&P production volume (boe/d)	**102,107**	**151,488**	**68,011**	**157,755**	D&P Production pg. 9
Combined Operating Netback ($/boe)					
ICE BRENT price	45.13	53.6	51.06	44.69	
Hedge effect	4.39	5.23	(1.52)	8.47	
Differential	(9.16)	(10.32)	(7.62)	(11.94)	
Crude oil and natural gas sales price	40.36	48.51	41.92	41.22	Sales pg. 11
Production cost of barrels	(8.98)	(8.54)	(12.63)	(9.10)	
Transportation (trucking and pipeline)	(12.33)	(11.89)	(14.82)	(10.61)	
Diluent cost	(1.47)	(2.05)	(0.53)	(2.30)	
Total Operating cost	**(22.78)**	(22.48)	**(27.98)**	(22.01)	Operating costs pg 13
Operating netback crude oil and gas ($/boe)	**17.58**	**26.03**	**13.94**	**19.21**	
Fees paid on suspended pipeline capacity	(2.81)	(2.24)	(2.98)	(2.88)	Operating costs pg 13
Share of gain of equity-accounted investees - pipelines	1.72	0.99	2.34	1.08	Equity investees pg 16
Consolidated netback ($/boe)	**16.49**	**24.78**	**13.3**	**17.41**	
General and administrative expenses	(3.87)	(3.67)	(6.34)	(3.76)	G&A pg 15
Cash finance costs	(3.31)	(4.89)	(1.50)	(3.95)	Finance costs pg 16
Cash netback ($/boe)	**9.31**	**16.22**	**5.46**	**9.70**	

In 2016, the Company's average combined realized oil and gas price from operated barrels decreased to $40.36/boe from $48.51/boe, due to the decline in world crude prices. Comparing the fourth quarter of 2016 with the same period of 2015, the average combined realized oil and gas price increased from $41.22/boe to $41.92/boe.

Total operating costs, including production, transportation, and dilution costs, increased from $22.48/boe in 2015 to $22.78/boe in 2016. During 2016, the Bicentenario pipeline was not operational for an average of 185 days; however, the Company was able to source available operational capacity from the OCENSA pipeline at comparable costs per unit.

Net Production and Development Review

The following table highlights the average daily net share production after royalties from all of the Company's producing fields in Colombia and Peru, reconciled to volume sold.

	Year Ended December 31		Three Months Ended December 31	
Producing fields (boe/d)	**2016**	**2015**	**2016**	**2015**
Rubiales / Piriri	23,861	54,713	-	54,713
Quifa SW (1)	25,094	29,643	22,135	29,818
Light and medium (2)	39,607	51,436	35,182	50,959
Gas (3)	8,763	9,227	7,203	10,463
Heavy oil (1) (4)	3,101	3,867	2,833	3,416
Total production Colombia	**100,426**	**148,886**	**67,353**	**149,369**
Peru - Light and medium (5)	3,106	5,586	2,079	10,462
Total crude oil and natural gas production	**103,532**	**154,472**	**69,432**	**159,831**
D&P crude oil and natural gas production	102,107	151,488	68,011	157,755
E&E crude oil and natural gas production	1,425	2,984	1,421	2,076
Total crude oil and natural gas production	**103,532**	**154,472**	**69,432**	**159,831**
Crude oil inventory (build) draw	(8,040)	119	(953)	12,653
Average daily sales of produced crude oil and natural gas	**95,492**	**154,591**	**68,479**	**172,484**
Crude oil purchased	1,282	6,914	2,544	864
Sales from E&E assets (boe/d)	(1,278)	(2,392)	(1,370)	(1,420)
Volume sold oil and gas including trading (boe/day)	**95,496**	**159,113**	**69,653**	**171,928**

1. *The Company's share before royalties in the Quifa SW and Cajua fields is 60% and decreases in accordance with a high-price clause ("**PAP**") that assigns additional production to Ecopetrol S.A. ("**Ecopetrol**").*
2. *Mainly includes Cubiro, Cravoviejo, Casanare Este, Canaguaro, Guatiquia, Casimena, Corcel, CPI Neiva, Cachicamo, Arrendajo and other producing fields.*
3. *Includes La Creciente, Dindal/Rio Seco, Cerrito, and Guama fields.*
4. *Includes Cajua, Sabanero, CPE-6, Rio Ariari, Prospecto S and Prospecto D fields.*
5. *Includes Block 192, where normal production should be 12,000 bbl/d gross; however, oil production has been halted since February 23, 2016, due to a force majeure at the Block arising from the shutdown of the Norperuano Pipeline.*

During 2016, net production after royalties and internal consumption totalled 103,352 boe/d, representing a decrease of 51,120 boe/d (33%) from the average net production of 154,472 boe/d reported in the previous year. This reduction is mainly attributable to the expiration of the Rubiales and Piriri fields, both of which were returned to Ecopetrol on June 30, 2016.

During 2016, heavy oil production from Quifa SW and other fields decreased by 16% in comparison with 2015, mainly due to lower drilling activity and operational issues with water disposal capacity. Light and medium net oil production in Colombia and Peru totalled 42,713 bbl/d, decreasing by 25% compared with 2015 (57,022 bbl/d). The overall decrease was primarily due to lower drilling activity as a result of reduced capital expenditures during the Company's restructuring process in 2016. Light and medium oil and heavy oil production (excluding production at the Rubiales field) now represent 41% and 27%, respectively, of total net oil and gas production. Additionally, gas production decreased 5% compared with the year 2015 due to operational issues, and as of December 31, 2016 represented 8% of the total production.

Colombia

The Company continues to operate fields and facilities to maximize production while investing in impactful capital projects. Net production after royalties in Colombia for the fourth quarter of 2016 was 67,353 boe/d (93,452 boe/d total field production), down from 149,369 boe/d (295,491 boe/d total field production) in the same period of 2015, and 8% lower than the 72,914 boe/d in the third quarter of 2016 (99,804 boe/d total field production).

The Company and Ecopetrol signed a termination agreement for the return of the Rubiales and Piriri fields upon the expiration of the contract on June 30, 2016. Both parties have been actively involved to ensure a smooth transition of the operatorship. Pursuant to the Rubiales-Piriri contract, all fixed assets located in these fields were transferred to Ecopetrol along with the operatorship without compensation. Therefore, all net book value of fixed assets associated with these fields has been fully depleted.

Peru

The Company's production from Peru consists of a 49% participating interest in Block Z-1, a 30% working interest in the Los Angeles discovery in Block 131, and the Block 192 services contract. Net production after royalties for the fourth quarter of 2016 totalled 2,079 bbl/d, an 80% decrease from 10,462 bbl/d in the same period of 2015.

Proved and Probable Oil and Gas Reserves

For the year ended December 31, 2016, the Company received independent certified reserves evaluation reports for all of its assets with total net 2P reserves of 170.7 MMboe. Compared with 290.8 MMboe certified for the year ended 2015, the year-over-year decline is mainly due to production for the year, the lower oil price forecasts resulting in economic revisions and the impact of technical revisions as assessed by the Company's independent reserves evaluators. Proved net reserves of 117.3 MMboe now represent 69% of the total 2P reserves compared with 68% of the total 2P reserves in 2015.

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 14, 2017.

Reserves at December 31, 2016 (MMboe[1])									
Country	**Field**	**Proved (P1)**		**Probable (P2)**		**Proved + Probable (2P)**		**Hydrocarbon Type**
		Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	
Colombia	Quifa SW	47.2	41.3	3.5	3.0	50.7	44.3	Heavy Oil
	Other Heavy Oil Blocks[2]	32.5	28.1	14.5	12.2	47.0	40.3	Heavy Oil
	Light/Medium Oil Blocks	38.8	35.7	28.0	25.7	66.8	61.4	Light & Medium Oil, Associated Natural Gas
	Natural Gas Blocks[3]	6.7	6.7	7.9	7.9	14.6	14.6	Natural Gas
	Sub-total	**125.3**	**111.8**	**53.8**	**48.7**	**179.1**	**160.5**	Oil & Natural Gas
Peru	Light/medium oil/natural gas[4]	6.5	5.5	4.7	4.7	11.2	10.2	Oil & Natural Gas
	Total at Dec. 31, 2016	**131.8**	**117.3**	**58.5**	**53.4**	**190.3**	**170.7**	Oil & Natural Gas
	Total at Dec. 31, 2015	216.6	197.8	101.2	93.0	317.8	290.8	
	Difference	**(84.8)**	**(80.5)**	**(42.7)**	**(39.6)**	**(127.4)**	**(120.1)**	
	2016 Production	41.9	37.9	**Total Reserves Incorporated**		**(85.6)**	**(82.2)**	

1. *See "Boe conversion" on the "Advisories" section, page 35.*
2. *Includes Cajua, Jaspe, Quifa North, Sabanero, CPE-6 and Rio Ariari properties.*
3. *Includes La Creciente field.*
4. *Includes onshore Block 131, Block 192, and offshore Block Z1.*
5. *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.*

Inventory Movement

(boe/d)	2016 Q4	2016 Q3	2016 Q2	2016 Q1
Crude oil inventory - beginning of the period	4,329	15,196	3,920	820
Crude oil and natural gas production	69,432	75,096	127,951	142,338
Crude oil and natural gas sales	(71,023)	(83,650)	(111,102)	(121,745)
Crude oil purchased	2,544	743	166	1,777
Overlift movement	(16)	38	(166)	(14,752)
Operational Consumption	(2,054)	(1,528)	(3,610)	(2,591)
Volumetric compensation	(601)	(1,566)	(1,963)	(1,927)
Crude oil inventory - end of period	2,611	4,329	15,196	3,920

Sales

(in thousands of US$)	Year Ended December 31 2016	Year Ended December 31 2015	Three Months Ended December 31 2016	Three Months Ended December 31 2015
Net crude oil and gas sales and other income	$ 1,246,948	$ 2,363,434	$ 269,564	$ 480,590
Hedge	152,116	289,845	(9,441)	133,228
Overlift	56	34,808	56	34,808
Trading revenue	12,591	136,459	9,593	3,344
Total sales	**$ 1,411,711**	**$ 2,824,546**	**$ 269,772**	**$ 651,970**
Total sales excluding trading revenue	1,399,120	2,688,087	260,179	648,626
$/per volume sold	40.36	48.51	41.92	41.22

The following is an analysis of the price and sales volume movements for the year and fourth quarter of 2016 in comparison with the same periods of 2015:

(in thousands of US$)	Year 2016 - 2015
Total sales for the year ended December 31, 2015	$ 2,824,546
Decrease due to lower produced and sold volume by 37% (52,998 boe/d)	(971,497)
Decrease due to lower volume of trading by 89% (6,527 bbl/d)	(121,841)
Overlift	(34,752)
Hedge effect	(137,729)
Decrease due to lower realized prices by 17%	(147,016)
Total sales for the year ended December 31, 2016	**$ 1,411,711**

(in thousands of US$)	4Q 2016 - 2015
Total sales for the quarter ended December 31, 2015	$ 651,970
Decrease due to lower produced and sold volume by 61% (11,445 boe/d)	(358,007)
Increase due to higher volume of trading by 146% (325 bbl/d)	4,868
Overlift	(34,752)
Hedge effect	(142,669)
Increase due to higher realized prices by 2%	148,362
Total sales for the quarter ended December 31, 2016	**$ 269,772**

Total sales during 2016 were $1,412 million, 50% lower than 2015 revenues of $2,825 million. This decrease is the result of the expiration of the Rubiales-Piriri contract on June 30, 2016, lower realized oil prices, and lower trading volumes sold.

Total sales in the fourth quarter of 2016 were $270 million, 59% lower than the $652 million in the same period in 2015. This decrease is the result of lower volumes sold.

Realized and Reference Prices

	Year Ended December 31		Three Months Ended December 31	
	2016	2015	2016	2015
Reference prices				
WTI NYMEX ($/bbl)	43.47	48.76	49.29	42.16
ICE BRENT ($/bbl)	45.13	53.60	51.06	44.69
Henry Hub average natural gas price ($/MMBtu)	2.55	2.63	3.18	2.23
Realized prices				
Oil realized price ($/bbl)	41.80	49.56	43.78	41.86
Gas realized price ($/boe)	25.52	32.28	25.12	31.43
Combined realized price oil and gas $/boe (excluding trading)	35.97	43.28	43.44	32.75
Realized hedging gain (loss) $/boe	4.39	5.23	(1.52)	8.47
Combined Realized price after hedging $/boe	**40.36**	**48.51**	**41.92**	**41.22**

Average crude oil and gas combined realized price for the year ended December 31, 2016 reached $40.36/boe, $8.15/boe lower compared with the year ended December 31, 2015.

In 2016, the WTI NYMEX price decreased by $5.29/bbl (11%) to an average of $43.47/bbl compared with the average of $48.76/bbl in 2015. The ICE BRENT price declined by $8.47/bbl (16%) to an average of $45.13/bbl compared with the average of $53.60/bbl in 2015.

During the fourth quarter of 2016, the WTI NYMEX price increased by $7.13/bbl (17%) to an average of $49.29/bbl compared with the average of $42.16/bbl in the same period of 2015. Likewise, the ICE BRENT price increased by $6.37/bbl (14%) to an average of $51.06/bbl compared with the average of $44.69/bbl in the same period of 2015.

Trading Netback

	Year Ended December 31		Three Months Ended December 31	
	2016	2015	2016	2015
Average daily volume sold (bbl/d)	**780**	**7,307**	**2,183**	**889**
Operating netback ($/bbl)				
Crude oil traded sales price	44.11	51.16	47.76	40.89
Cost of purchases of crude oil traded	40.34	48.35	45.33	30.87
Operating netback crude oil trading ($/bbl)	**3.77**	**2.81**	**2.43**	**10.02**

In 2016, the Company traded an average of 780 bbl/d compared with 7,307 bbl/d in the same period of 2015. The average netback for volumes traded in 2016 was $3.77/bbl versus the netback obtained in the same period of 2015 of $2.81/bbl. The drop in the volumes sold in 2016 was mainly attributable to the reduction in oil production in Colombia, which allowed other traders to utilize the available capacity in pipelines to be more competitive.

The nature of the Company's oil trading business is opportunistic and often depends on the available capacity under the pipeline transportation agreements. The Company's ability to acquire crude oil for trading purposes allows it to use any available capacity and offset the take-or-pay transportation fees.

Operating Costs

(in thousands of US$)	Year Ended December 31 2016	Year Ended December 31 2015	Three Months Ended December 31 2016	Three Months Ended December 31 2015
Production costs	$ 335,765	$ 472,466	$ 79,049	$ 132,119
$/per boe D&P production	8.98	8.54	12.63	9.10
Transportation costs	460,605	657,270	92,754	153,924
$/per boe D&P production	12.33	11.89	14.82	10.61
Diluent cost	55,108	113,141	3,285	33,345
$/per boe D&P production	1.47	2.05	0.53	2.30
Total operating cost	**$ 851,478**	**$ 1,242,877**	**$ 175,088**	**$ 319,388**
Average operating cost per boe	**$ 22.78**	**$ 22.48**	**$ 27.98**	**$ 22.01**
Take-or-pay fees on disrupted transport capacity Bicentenario	105,129	123,818	18,648	41,819
$/per boe D&P production	2.81	2.24	2.98	2.88
Trading purchase cost	11,515	128,948	9,104	2,525
$/per bbl trading	40.35	48.35	45.33	30.87
Other costs [1]	(5,593)	48,365	1,713	15,316
(Underlift) overlift	(34,864)	35,445	(48)	35,324
Total cost	**$ 927,665**	**$ 1,579,453**	**$ 204,505**	**$ 414,372**

1. *Other costs mainly correspond to inventory fluctuation, and the net effect of the currency hedge of operating expenses incurred in Colombian pesos for the year ended December 31, 2015.*

Total operating costs for 2016 were $851 million, a 32% decrease from the $1,243 million in 2015 mainly due to lower volumes after the expiration of Rubiales which, as a mature field, had lower costs than other fields. In addition, transportation costs increased due to lower transported volumes and the fixed rates of the Company's ship-or-pay agreements.

For the fourth quarter of 2016, total operating costs were $175 million, a 45% decrease from the $319 million for the same period of 2015. The reduction in costs resulted from cost optimization strategies adopted as a response to the lower oil price environment.

In addition, trading purchase costs decreased from $129 million in 2015 to $12 million for 2016, mainly due to lower sales volumes.

Depletion, Depreciation and Amortization

(in thousands of US$)	Year Ended December 31 2016	Year Ended December 31 2015	Three Months Ended December 31 2016	Three Months Ended December 31 2015
Depletion, depreciation and amortization	$ 575,985	$ 1,529,016	$ 85,700	$ 380,281
$/per boe D&P production	15.41	27.65	13.70	26.20

During 2016 DD&A decreased to $576 million, from $1,529 million in 2015. The 62% decrease is primarily due to the lower carrying amount of oil and gas properties resulting from the impairments recognized during recent years, and due to the full depletion of the Rubiales-Piriri field upon termination of the contract on June 30, 2016. Unit DD&A for the fourth quarter of 2016 was $13.70/boe, 48% lower than the $26.20/boe for the same period of 2015. During 2016, oil and gas assets were depleted over the Company's proved reserves (2015: proved and probable reserves).

Impairment and Impairment Reversal

(in thousands of US$)	Year Ended December 31 2016	Year Ended December 31 2015	Three Months Ended December 31 2016	Three Months Ended December 31 2015
Impairment of oil & gas properties and plant and equipment	$ 271,957	$ 2,344,587	$ (613,313)	$ 1,988,587
Impairment of exploration and evaluation assets	22,302	2,058,969	(23,639)	1,783,969
Impairment of other assets	182,746	49,364	358	38,406
Impairment of goodwill	-	237,009	-	-
Exploration expenses	-	217,280	-	79,267
Total impairment and exploration expenses	**$ 477,005**	**$ 4,907,209**	**$ (636,594)**	**$ 3,890,229**

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) may be impaired. The Company considers changes in the market, economic and legal environments in which the Company operates that are not within its control and affect the recoverable amount of the oil and gas, exploration and evaluation properties. The recoverable amount is calculated based on the higher of value-in-use and fair value less costs of disposal. The Company records an impairment when the recoverable amount of the CGU exceeds its carrying amount.

For assets excluding goodwill, an assessment is made at each reporting date as to whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such indication exists, the Company estimates the asset's or CGU's recoverable amount. A reversal gain is recorded if the previously recognized impairment charge has decreased or no longer exists, subject to certain limitations.

During the year 2016, the Company recorded a net impairment charge of $477 million, including impairment losses of $1,113.6 million and a reversal of impairment of $636.9 million. The impairment losses recognized during the year related to lower recoverable amounts in the CGUs in Colombia and Peru due to lower price assumptions and technical revisions. During the fourth quarter of 2016, the Company identified several indications for impairment reversal, including:

- The successful completion of the Restructuring Transaction significantly reduced the Company's long-term debts and the uncertainty with respect to the Company's ability to continue as a going concern and finance its near-term capital programs.
- The net present value of the proved and probable reserves as indicated in the Company's certified reserve reports as of December 31, 2016 was higher than the carrying amount of the oil and gas assets.

Based on the above indications and the updated recoverable amounts for the CGUs in Colombia and Peru, we recognized a reversal of impairment of $636.9 million in the fourth quarter of 2016.

The table below summarizes the impairment charges for the year ended December 31, 2016:

(in thousands of US$)	Year Ended December 31 2016	2015
Oil and Gas Properties (D&P)		
North Colombia CGU	$ 163,400	$ 167,642
Central Colombia CGU	(123,575)	1,564,759
South Colombia CGU	11,000	238,426
Peru	96,599	323,660
Power line transmission	58,105	-
Water treatment plant	32,863	50,100
Plant and Equipment (PP&E)		
Colombia	30,498	-
Panama	3,067	-
Exploration and Evaluation Properties (E&E)		
Colombia	(4,874)	1,242,551
Belize	664	18,890
Peru	20,610	277,222
Brazil	5,883	421,120
Papua New Guinea	-	13,000
Other	19	86,186
Total Impairment impact D&P, PP&E and E&E	**$ 294,259**	**$ 4,403,556**
Goodwill allocated to Colombia	-	237,009
Total impairment of properties	**$ 294,259**	**$ 4,640,565**

For more information please refer to Note 21 – Impairment and Exploration Expenses in the Consolidated Financial Statements for the year ended December 31, 2016.

General and Administrative Costs

(in thousands of US$)	Year Ended December 31 2016	2015	Three Months Ended December 31 2016	2015
General and administrative costs	$ 144,538	$ 203,153	$ 39,640	$ 54,506
$/per boe D&P production	3.87	3.67	6.34	3.76

G&A costs excluding severance and restructuring costs decreased to $145 million in 2016 from $203 million in 2015, mainly due to continuing efforts to minimize discretionary spending and reduce overhead. G&A costs per boe increased by $0.20/boe to $3.87/boe from $3.67/boe in 2015 due to the decrease in produced volume during the year.

Restructuring and Severance Costs

(in thousands of US$)	Year Ended December 31 2016	2015	Three Months Ended December 31 2016	2015
Restructuring cost	$ 121,608	$ -	$ 30,092	$ -
Severance	33,247	18,311	24,942	7,870
Total restructuring and severance costs	$ 154,855	$ 18,311	$ 55,034	$ 7,870

For the year ended December 31, 2016, the Company incurred $155 million in costs related to the Restructuring Transaction and severance costs.

Finance Costs

	Year Ended December 31		Three Months Ended December 31	
(in thousands of US$)	2016	2015	2016	2015
Cash finance costs	$ 123,779	$ 270,147	$ 9,361	$ 57,278
Non-cash finance costs	67,466	164,699	57,136	148,639
Total finance costs	$ 191,245	$ 434,846	$ 66,497	$ 205,917
Cash finance costs $/per boe D&P production	3.31	4.89	1.50	3.95

Finance costs include interest on the Company's long-term debts, working capital loans, finance leases, and fees on letters of credit, net of interest income received. For the year 2016, finance costs also included interest on the DIP notes.

During 2016, finance costs decreased to $191 million from the $435 in 2015, and for the three months ended December 31, 2016, finance costs totalled $66 million, lower than the $206 million in the same period of 2015 and mainly as a result of the senior notes and the credit facilities ceasing to accrue interest on April 27, 2016 when the Company received the Initial Order for the Restructuring Transaction.

Share of Gain (Loss) of Equity-Accounted Investees

	Year Ended December 31		Three Months Ended December 31	
(in thousands of US$)	2016	2015	2016	2015
Share of gain of equity-accounted investees - pipelines	$ 64,329	$ 54,538	$ 14,617	$ 15,625
Share of loss of equity-accounted investees other than pipelines	$ (1,489)	$ (33,001)	$ (18,870)	$ (7,750)
Total share of gain (loss) of equity-accounted investees from pipelines	$ 62,840	$ 21,537	$ (4,253)	$ 7,875
Share of gain of equity-accounted investees - pipelines $/per boe D&P production	1.72	0.99	2.34	1.08

During 2016, the Company's share of gain of equity-accounted investees increased from $22 million to $63 million gain in 2015, mainly due to lower losses from Pacific Infrastructure and other non-pipeline investees. For the three months ended December 31, 2016, the Company's share of loss from equity-accounted investees totalled $4 million, lower than the $7 million gain in the same period of 2015, mainly as a result of an impairment charge recorded by one of the investees.

Foreign Exchange

	Year Ended December 31		Three Months Ended December 31	
(in thousands of US$)	2016	2015	2016	2015
Foreign exchange gain (loss)	$ 8,863	$ (134,477)	$ (13,857)	$ (21,396)

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 working capital and expenditures are denominated in COP. During 2016, the COP appreciated against the U.S. dollar by 4.7%, compared with a depreciation of 32% during 2015 (foreign exchange close rates from COP – U.S. dollar were COP$3,000.71 for 2016 and COP$3,149.47 in 2015). The foreign exchange gain in 2016 was $9 million compared with a loss of $134 million in 2015 and was primarily due to the impact the appreciation of the COP had on the translation of the Company's net working capital.

(Loss) Gain on Risk Management

(in thousands of US$)	Year Ended December 31 2016	Year Ended December 31 2015	Three Months Ended December 31 2016	Three Months Ended December 31 2015
(Loss) Gain on Risk Mangement	$ (139,457)	$ 129,474	$ (13,471)	$ 61,553

The (loss) gain on risk management represented the unrealized gain or loss arising from the movement in the mark-to-market values of the Company's risk management contracts during each period. During 2016, the Company entered into several oil price risk management contracts to hedge against oil price volatility; as of December 31, 2016 the Company had hedges for production through March 2017. The hedging portfolio consisted of zero-cost collars. As at December 31, 2016, the Company had hedge positions for approximately 10 Million barrels of oil with floor and ceiling strike prices of $47.73/bbl and $55.78/bbl ICE BRENT, respectively, with a net liability of $38.4 million.

In addition to derivative contracts, the Company also entered into a forward-sale contract with a floor price of $46.0/bbl and a ceiling of $49.6/bbl ICE BRENT (subject to a price differential on the ICE BRENT) whereby the Company shall deliver 500,000 barrels per month from September 2016 until February 2017. On December 15, 2016 the Company upgraded an outstanding contract of 500,000 barrels per month for January and February 2017 to a floor price of $50/bbl and a ceiling of $53/bbl ICE BRENT (subject to a price differential on the ICE BRENT) and extended the contract whereby the Company shall deliver 500,000 barrels per month from June 2017 to July 2017.

None of the risk management contracts outstanding as of December 31, 2016 have been designated as accounting hedges.
As of the release of this report, the company has actively engaged in building new hedging positions for 2017, progressively closing volumes of up to 1.4 million barrels per month up to October 2017, to continue protecting cash flows from a potential downturn in the price of oil.

Income Tax Expense

(in thousands of US$)	Year Ended December 31 2016	Year Ended December 31 2015	Three Months Ended December 31 2016	Three Months Ended December 31 2015
Current income tax expense	$ (42,522)	$ (50,226)	$ (1,113)	$ (7,909)
Deferred income tax recovery: Relating to origination and reversal of temporary differences	6,347	516,740	3,891	366,578
Total income tax (expense) recovery	**$ (36,175)**	**$ 466,514**	**$ 2,778**	**$ 358,669**

Current income tax totalled $42.5 million in the year ended December 31, 2016 as compared to $50.2 million in the year ended December 31, 2015. The variation is mainly attributable to the decrease in profits in the Colombian entities therefore subject to a minimum income tax (presumptive income). The income tax is composed of $31.6 million of current tax in Colombia, a write-off of the income tax receivables for $1.8 million, tax amendments of $7.0 million and the current tax in countries different than Colombia of $2.1 million.

The 2016 wealth tax paid totaled $26 million. Based on the Company's taxable base, the Company has not made an accrual for future years, pursuant to IAS 37 and IFRIC 21.

For more information please refer to Note 9 - Income Tax in the Consolidated Financial Statements

Capital Expenditures

(in thousands of US$)	Year Ended December 31 2016	Year Ended December 31 2015	Three Months Ended December 31 2016	Three Months Ended December 31 2015
Production facilities	$ 32,412	$ 132,856	$ 7,895	$ 47,584
Exploration activities	29,428	172,373	924	18,985
Early facilities and others	5,130	6,153	1,628	2,511
Development drilling	83,989	363,992	51,501	76,927
Other projects	10,503	50,138	2,300	14,147
Total capital expenditures	**$ 161,462**	**$ 725,512**	**$ 64,248**	**$ 160,154**

Capital expenditures during 2016 totalled $161.5 million, $564.0 million lower than the $725.5 million in 2015. During 2016, a total of $32.5 million was invested in the expansion and construction of production infrastructure, primarily in the Quifa SW, Cubiro, Cravoviejo, Casimena, Guatiquia, Corcel, Orito, Neiva, Block Z-1, Lot 131, Arrendajo and La Creciente fields; $29.4 million went into exploration activities, mainly invested in Brazil, Peru and Colombia; $5.1 million went into facilities and others; $84.0 million went into development drilling mainly in Quifa SW, Guatiquia, Arrendajo, Cubiro, Orito and Corcel; and $10.5 million was invested in other projects.

In light of the current weak commodity price environment, since the second half of 2015 the Company's capital expenditure programs have been scaled back significantly to focus on high-impact development drilling and minimum committed capital programs.

Selected Quarterly Information

(in thousands of US$ except as noted)	2016 Q4	2016 Q3	2016 Q2	2016 Q1	2015 Q4	2015 Q3	2015 Q2	2015 Q1
Financial and Operational results:								
Average daily oil and natural gas production (boe/d)	69,432	75,096	127,951	142,337	159,831	152,915	152,428	152,650
Average daily oil production (boe/d)	62,229	67,128	118,526	131,856	149,368	143,028	144,455	144,094
Average daily natural gas production (boe/d)	7,203	7,968	9,425	10,481	10,463	9,887	7,973	8,556
Net oil and natural gas sales (boe/d)	67,470	81,877	109,736	120,220	171,039	139,270	132,417	164,562
Combined realized sales price – oil and natural gas ($/boe)	41.92	40.83	37.60	41.67	41.22	51.49	53.72	49.45
Realized oil and gas price ($/boe)	43.44	40.83	37.60	26.9	32.75	41.70	55.35	46.02
Realized oil hedging ($/boe)	(1.52)	-	-	14.77	8.47	9.79	(1.63)	3.43
ICE BRENT ($/bbl)	51.06	46.99	47.03	35.21	44.69	51.30	63.50	55.13
Operating cost ($/boe)	(27.98)	(24.54)	(20.53)	(21.35)	(22.01)	(20.93)	(22.30)	(24.71)
Operating netback crude oil and gas ($/boe)	13.94	16.29	17.07	20.32	19.21	30.56	31.42	24.74
Consolidated netback crude oil and gas ($/boe)	13.30	12.35	17.01	19.58	17.41	27.93	30.14	25.48
Cash netback crude oil and gas ($/boe)	5.46	4.77	11.47	11.46	9.70	19.51	21.06	16.38
Net sales	$ 269,772	$ 308,705	$ 376,403	$ 456,831	$ 651,970	$ 669,995	$ 702,733	$ 799,848
Net earnings (loss) attributable to equity holders of the parent for the period	4,025,194	(557,068)	(118,654)	(900,949)	(3,895,908)	(617,318)	(226,377)	(722,256)
(Loss) Earnings per share - basic	1,277.75	(176.84)	(37.67)	(286.00)	(1,236.71)	(197.07)	(72.27)	(230.56)
Operating EBITDA	44,275	89,846	120,452	190,064	224,911	331,974	335,235	273,638
Consolidated EBITDA	(1,967)	37,689	126,083	91,814	257,584	414,550	196,592	242,840
Capital expenditures	64,248	30,061	48,349	18,804	160,154	154,281	185,043	226,034
Total assets (end of period)	2,741,719	2,403,602	2,990,699	2,687,858	3,986,121	8,290,772	9,376,943	9,969,913

Non-GAAP Measures

This report contains the following financial terms that are not considered in IFRS: Operating and Consolidated EBITDA, and Operating, Consolidated and Cash Netback. 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 measures should not be considered in isolation or as a substitute for measures of performance prepared in accordance with IFRS. These financial measures are included because management uses this information to analyze operating performance and liquidity. They are different from those measures disclosed in prior periods, reflecting the Company's new strategic focus on operational efficiency and capital discipline.

Operating and Consolidated EBITDA

Management believes that EBITDA is a common measure used to assess profitability before the impact of different financing methods, income taxes, depreciation and impairment of capital assets and amortization of intangible assets.

- Operating EBITDA represents the operating results of the Company's primary business, excluding the effects of capital structure, other investments (infrastructure assets), non-cash items that depend on accounting policy choices, and one-time items that are not expected to recur.
- Consolidated EBITDA excludes items of a nonrecurring nature (one-time items), or that could make the period-over-period comparison of results from operations less meaningful, but includes results from the Company's other investments (infrastructure assets).

A reconciliation of Operating and Consolidated EBITDA to Net Income is as follows:

	Year Ended December 31		Three Months Ended December 31	
(in thousands of US$)	2016	2015	2016	2015
Net income (loss) [(1)]	**$ 2,448,523**	**$ (5,461,859)**	**$ 4,025,194**	**$ (3,895,908)**
Adjustments				
Income tax expense (recovery)	36,175	(466,514)	(2,778)	(358,669)
Depletion, depreciation and amortization	575,985	1,529,016	85,700	380,281
Impairment and exploration expenses	477,005	4,907,209	(636,594)	3,890,229
Finance costs	191,245	434,846	66,497	205,917
Net gain on restructuring	(3,620,481)	-	(3,620,481)	-
Restructuring and severance costs	154,855	18,311	55,034	7,870
Equity tax	26,901	39,149	-	-
Other (income) expenses	(25,967)	80,992	15,661	27,914
Foreign exchange unrealized (gain) loss	(10,622)	30,416	9,800	(50)
Consolidated EBITDA	**253,619**	**1,111,566**	**(1,967)**	**257,584**
Loss (gain) on risk management	139,457	(129,474)	13,471	(61,553)
Share of (gain) loss of equity-accounted investees	(62,840)	(21,537)	4,253	(7,875)
Gain (loss) attributable to non-controlling interest	15,288	(21,112)	5,085	(20,265)
Share based compensation (gain) loss	(7,775)	(1,564)	728	(6,245)
Foreign exchange realized loss	1,759	104,061	4,057	21,446
Fees paid on suspended pipeline capacity	105,129	123,818	18,648	41,819
Operating EBITDA	**$ 444,637**	**$ 1,165,758**	**$ 44,275**	**$ 224,911**

Netbacks

Management believes that Netback is a useful measure to assess the net profit after all the costs associated with bringing one barrel of oil to the market. It is also commonly used by the oil and gas industry to analyze financial and operating performances expressed as profit per barrel.

- Operating Netback represents realized price per barrel plus realized gain or loss on financial derivatives, less production costs, transportation cost and diluent cost, and shows how efficient the Company is at extracting and selling its product.
- Consolidated Netback represents Operating Netback plus the results from corporate investments such as our pipeline investments that are in addition to oil and gas production and the take-or-pay tariffs paid on disrupted pipelines.
- Cash Netback represents Consolidated Netback less corporate cash expenses (general and administrative expenses and cash finance costs).

Financial Position

Pursuant to the Restructuring Transaction, all of the Company's senior unsecured notes and credit facilities outstanding prior to the Restructuring Transaction were cancelled in exchange for newly issued shares of the reorganized company (refer to page 4 - Restructuring Transaction). Upon completion of the Restructuring Transaction and as of December 31, 2016, the only long-term borrowing of the Company consisted of the five-year Senior Secured Notes due 2021 bearing interest at 10% per annum.

Covenant/Limitation on Indebtedness

Under the Indenture of the Senior Secured Notes due on 2021, the Company may not incur, directly or indirectly on any indebtedness before November 2, 2018. Subsequent to November 2, 2018, and after giving effect to certain conditions provided under the Indenture, the Company may incur additional indebtedness provided that the Company complies with the following financial covenants:

Covenant	Ratio
Consolidated Debt to Consolidated Adjusted EBITDA (1)	3.25
Consolidated Fixed Charge (2)	2.50

1. *Consolidated Debt to Consolidated Adjusted EBITDA Ratio is defined in the Indenture as the consolidated total indebtedness as of such date divided by Consolidated Adjusted EBITDA on a last-twelve-months basis. Consolidated Adjusted EBITDA is defined as the consolidated net income plus: i) interest expense; ii) income tax and equity tax; iii) depletion and depreciation expense; iv) amortization expense and v) impairment charge, exploration expense and abandonment costs.*
2. *Consolidated Fixed Charge Ratio means at any date, the result of dividing the Consolidated Adjusted EBITDA for the most recent ended period of four consecutive fiscal quarters and the consolidated interest expense for such period.*

Other covenants such as: Limitation on Sale of Assets, Limitation on Liens, Limitation on Lease-back Transactions and others, are included within the Indenture of the Senior Notes, with some exceptions.

Letters of Credit

As at December 31, 2016, the Company had issued letters of credit and guarantees for exploration and operational commitments for a total of approximately $163 million.

Outstanding Share Data

Common shares

As at March 14, 2017, 50,002,363 common shares were issued and outstanding.

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

Deferred share units

As at March 14, 2017, there were 23,388 DSUs outstanding. DSUs are instruments that may be settled in cash or common shares that track the price of the common shares and are payable to eligible participants (being limited to directors of the Company) upon their departure from the Board of Directors of the Company.

Liquidity and capital resources

As at December 31, 2016, the Company had positive working capital of $206 million, comprised of $389 million in cash and cash equivalents, $61 million in restricted cash, $235 million in accounts receivable, $39 million in inventory, $59 million in income tax receivable, $4 million in prepaid expenses, $45 in assets held for sale, $576 million in accounts payable and accrued liabilities, $32 million in risk-management liability, $11 million in income tax payable, $4 million in the current portion of obligations under finance lease, and $3 million in asset retirement obligations.

Refer to “Financial Results – Covenant/Limitation on Indebtedness” on page 21 for details of certain events of default, covenant breaches and forbearance agreements with respect to the Company’s outstanding indebtedness. Refer to “Risks and Uncertainties” on page 36 for details of the risks and uncertainties relating to the Company’s liquidity and capital resources.

4. Commitments and Contingencies

The Company is involved in various claims and litigation arising in the normal course of business. There can be no assurance that such matters will be resolved in the Company's favour because the outcome of these matters is uncertain. 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 that it may be required to pay by reason thereof would have a material impact on its financial position, results of operations or cash flows.

Tax Review in Colombia

The DIAN is 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, 2016, the DIAN has reassessed $56.5 million of tax owing, including estimated interest and penalties, with respect to the denied deductions.

As at December 31, 2016, 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.

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 34 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% 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 terminate the assignment agreement early and the Company would be required to pay an amount determined in accordance with the agreement, estimated at $102.8 million. The Company did not receive 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 2019. The Company continues to pay monthly premiums and is currently in negotiation with Transporte Incorporado regarding the terms of the agreement and the minimum credit rating requirement. No provision has been recognized as of December 31, 2016, 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 May 2017. 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 right 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, 2016 relating to the breach of the credit rating requirement.

Upon completion of the Restructuring Transaction, the Company received a corporate ratings upgrades from Fitch to B and Standard & Poors, to B+.

Commitments

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

5. 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 Company's internal audit and legal compliance departments 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 following sets out the details of the Company's related-party transactions for the current year. During and subsequent to the Restructuring Transaction, there have been a number of executive and director departures since November 2, 2016, as a result, certain transactions disclosed below ceased to be with related parties as of the dates of their departures.

a. The Company has take-or-pay contracts with ODL Finance S.A. ("**ODL**") for the transportation of crude oil from the Company's fields to Colombia's oil transportation system for a total commitment of $176 million from 2017 to 2020. During the year ended December 31 2016 the Company paid $89.5 million to ODL (2015: $108.5 million) for crude oil transport services under the pipeline take-or-pay agreement and had accounts payable of $0.3 million (December 31, 2015: $13.1 million). In addition, the Company received $0.6 million from ODL during the year ended December 31, 2016 (2015: $2.9 million) with respect to certain administrative services and rental equipment and machinery. The Company did not have any accounts receivable from ODL as at December 31, 2016 (December 31, 2015: $0.1 million). The Company has an indirect interest of approximately 22% in ODL.

b. The Company has ship-or-pay contracts with Oleoducto Bicentenario de Colombia ("**Bicentenario**") for the transportation of crude oil from the Company's fields to Colombia's oil transportation system for a total commitment of $1.2 billion from 2017 to 2025. The Bicentenario pipeline has experienced periodic suspensions following security-related disruptions. During the year ended December 31, 2016, the Company paid $168.9 million to Bicentenario (2015: $155.6 million), a pipeline company in which the Company has a 43% interest, for crude oil transport services under the pipeline ship-or-pay agreement. During the year ended December 31, 2016, the Company recognized nil in interest income from Bicentenario on a shareholder loan that has since been repaid (2015: $1.3 million). The Company had an advance of $87.9 million as at December 31, 2016 (December 31, 2015: $87.9 million) to Bicentenario as a prepayment of transport tariff, which is to be amortized against future barrels transported above the Company's contract capacity. As at December 31, 2016, the Company had trade accounts receivable of $13.4 million (December 31, 2015: $0.4 million) from Bicentenario.

c. As at December 31, 2016, the Company had demand loans receivable from Pacific Infrastructure Ventures Inc ("**PII**") in the amount of $72.4 million (December 31, 2015: $72.4 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 41.77% of PII (December 31, 2015: 41.79%). Interest income of $9.4 million was recognized during the year ended December 31, 2016 (2015: $5 million) regarding the loan. In addition, during the year ended December 31, 2016, the Company received $2.7 million (2015: $3.7 million) from PII with respect to contract fees for advisory services and technical assistance in pipeline construction for "Oleoducto del Caribe." In addition, as at December 31, 2016, the Company had accounts receivable of $0.8 million (December 31, 2015: $0.5 million) from a branch of PII. As at December 31, 2016, the Company had accounts payable of $0.9 million to PII (December 31, 2015: $0.5 million).

   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, 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 for a total commitment of $200 million. During the year ended December 31, 2016, the Company paid $39.4 million to Sociedad Puerto Bahia S.A. (2015: $28.6 million) for storage, transfer, and loading and unloading of hydrocarbons. These agreements may indirectly benefit the other shareholders of PII, including Blue Pacific Assets Corp. ("**Blue Pacific**") and other unrelated parties. Three former directors (Serafino Iacono, Miguel de la Campa, and Jose Francisco Arata) and one former executive officer (Laureano Von Siegmund), who held these positions prior to the Restructuring Transaction, control or provide investment advice to the holders of 88% of the shares of Blue Pacific. During the year ended December 31, 2016, the Company paid nil in advances to Sociedad Puerto Bahía S.A. in relation to services received (2015: $28.6 million of which $10.9 million was expensed during the year ended December 31, 2015).

d. On February 29, 2016, the Company agreed to provide CGX Energy Inc. ("**CGX**") with a bridge loan of up to $2 million at an interest rate of 5% per annum, payable within 12 months of the first draw down. As at December 31, 2016, the amount CGX had drawn down from the bridge loan was $2 million, and the Company considers this loan to be fully impaired. Subsequently, on October 13, 2016, the Company agreed to provide CGX with an additional bridge loan of up to $2 million at an interest rate of 5% per annum and payable within 12 months of the first draw down. As at December 31, 2016, CGX had drawn down $1 million, and the Company considers this loan to be fully impaired.

   In October 2014, the Company extended a bridge loan to CGX of C$7.5 million with an interest rate of 5%, and as at December 31, 2016, the full amount is still outstanding and fully impaired. In addition, in November 2015, CGX issued convertible debentures to the Company in an amount of $1.5 million with a conversion price of C$0.335, and as at December 31, 2016, the Company has not converted the debentures.

e. In October 2012, the Company and Ecopetrol signed two Build, Own, Manage, and Transfer ("BOMT") agreements with Consorcio Genser Power-Proelectrica and its subsidiaries ("**Genser-Proelectrica**") to acquire certain power generation assets for the Rubiales field. Genser-Proelectrica is a joint venture between Proelectrica, in which the Company has a 21.1% indirect interest, and Genser Power Inc. ("**Genser**") which is 51% owned by Interamerican Energia Corp ("**Interamerican**," formerly Pacific Power Generation Corp.). On March 1, 2013, these contracts were assigned to TermoMorichal SAS ("**TermoMorichal**"), the company created to perform the agreements, in which Interamerican has a 51% indirect interest. Total commitment under the BOMT agreements is $229.7 million over 10 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 10 years. At the end of the Rubiales Association Contract on June 30, 2016, the Company's obligations along with the power generation assets were transferred to Ecopetrol. As at December 31, 2016, the Company did not have any advances to Genser-Proelectrica (December 31, 2015: $3.3 million).

   During the year ended December 31, 2016, the Company made payments of $20.2 million relating to power generation costs (2015: $30.6 million). The Company had accounts payable of $0.6 million (December 31, 2015: $3.6 million) due to Genser-Proelectrica as at December 31, 2016. 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 Promotora de Energia Electrica de Cartagena & Cia, S.C.A. E.S.P. ("**Proelectrica**"), guaranteeing obligations pursuant to an energy supply agreement in the aggregate amount of approximately $16.7 million aligned with the Company's participation. 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 two subsidiaries of the Company 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 ended December 31, 2016, the Company made payments of $17.2 million (2015: $46.3 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 ended December 31, 2016, the Company recorded revenues of $8.7 million (2015: $9.3 million) from such agreements. As at December 31, 2016, the Company had trade accounts receivable of $0.2 million (December 31, 2015: $12.3 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.

f. Revenue from Proelectrica in the normal course of the Company's business was $8.7 million for the year ended December 31, 2016 (2015: $9.3 million). Blue Pacific owns a 5% interest in Proelectrica. The Company and Blue Pacific's indirect interests are held through Interamerican.

g. On December 11, 2015 the Company and the other shareholders of Interamerican, including Proenergy Corp. (a subsidiary of Blue Pacific), entered into a share purchase agreement with Faustia Development S.A., Tusca Equities Inc., and Associated Ventures Corp. (the "**Interamerican Purchasers**") for the sale of 70% of the shares of Interamerican. As part of the transaction, the Company agreed to sell 4% of the Company's 24.9% equity interest in Interamerican to the Interamerican Purchasers for approximately $5 million. As a result of the sale, the Company currently owns 21.09% and Proenergy Corp. (Blue Pacific) currently owns approximately 5% of Interamerican. Associated Ventures Corp. was controlled by Alejandro Betancourt, a former director of the Company who resigned on April 27, 2016.

h. The Company has previously established two charitable foundations in Colombia: the Paye Foundation ("**Paye**," formerly the Pacific Rubiales Foundation) and the Foundation for Social Development of Energy Available ("**FUDES**"). FUDES was liquidated on September 28, 2016 and all pending obligations and commitments were assigned to Paye, which ceased its activities on December 31, 2016. Both foundations had the objective of advancing social and community development projects in the country. During the year ended December 31, 2016, the Company contributed $9.6 million to these foundations (2015: $15.3 million). As at December 31, 2016, the Company had accounts receivable (advances) of nil (December 31, 2015: $0.4 million) and accounts payable of $1.7 million (December 31, 2015: $3.2 million). An officer of the Company (Federico Restrepo) sits on the board of directors of Paye.

The Company's key management personnel include its Board of Directors and the executive officers.

	Year Ended December 31	
(in thousands of US$)	2016	2015
Short-term employee benefits	$ 26,610	$ 20,521
Termination benefits	20,603	-
Post-employment pension and medical benefits	3,295	1,437
Share-based payments	1,571	16,228
Total Compensation	**$ 52,079**	**$ 38,186**

The Company also had the following transactions with parties were related or officers of the Company at the time they were entered into, but who were no longer officers of the Company as of December 31, 2016.

a. As at December 31, 2016, interest free loans receivable from former directors and officers have been fully repaid (December 31, 2015: $0.5 million outstanding).

   In August 2015, the Company agreed to pay $8.3 million in severance to Jose Francisco Arata, an officer of the Company until August 14, 2015. The severance included $5.5 million in cash paid during 2015, $1.4 million paid in the three months ended March 31, 2016 and $1.4 million settled in new common shares of the Company as part of the Restructuring Transaction. In addition, the departing officer's DSU entitlement was paid in kind effective August 14, 2015 with the Company's shares held in treasury for a total of approximately 1.3 million common shares. Also during 2015, the Company made payments in kind of approximately 0.5 million common shares to 3 departing directors as settlement for DSU entitlements.

b. As of December 31, 2016 the Company had accounts payable of $1.9 million (December 31, 2015: $1.9 million) outstanding to Pacific Green with respect to contributions made previously by Pacific Green to Promotora Agricola, an agricultural project controlled by the Company. Pacific Green's contributions to the project are expected to be capitalized in the near term. Pacific Green was controlled by three former officers of the Company who retired in November 2016.

6. Accounting Policies, Critical Judgments, and Estimates

Basis of Presentation

The consolidated financial statements of the Company have been prepared in accordance with International Financial Reporting Standards ("**IFRS**") as issued by the International Accounting Standards Board ("**IASB**"). The consolidated financial statements have been prepared on a historical cost basis, except for derivative financial instruments and available-for-sale investments, which have been measured at fair value. The consolidated financial statements are presented in U.S. dollars and all values are rounded to the nearest thousand, except where otherwise indicated.

Significant Accounting Judgments, Estimates and Assumptions

The preparation of consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities and contingent liabilities at the date of the consolidated financial statements and reported amounts of revenues and expenses during the reporting period. Estimates and judgments are continuously evaluated and are based on management's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. However, actual outcomes can differ from these estimates.

Some of the areas where management was required to apply judgments included the accounting for the Plan Sponsor and Creditor DIP Notes, certain dilution and collaboration agreements, the determination of cash-generating units, and contingencies, among others.

Examples of areas that involved significant measurement uncertainty and assumptions included the oil and gas depletion method, estimation of recoverable amounts of assets and cash-generating units, termination of association contracts, and decommissioning costs.

Refer to Note 2 of the Consolidated Financial Statements as of December 31, 2016 for details on the Company's accounting policies, critical judgments, and estimates.

New Standards, Interpretations, and Amendments Adopted by the Company

There were a number of new standards and interpretations effective from January 1, 2016, that the Company applied for the first time. The nature and impact of each new relevant standard and/or amendment is described below. Other than the changes described below, the accounting policies adopted are consistent with those of previous financial years.

IFRS 5 Non-Current Assets Held for Sale and Discontinued Operations

Assets (or disposal groups) are generally disposed of either through sale or distribution to the owners. This amendment clarifies that changing from one of these disposal methods to the other would not be considered a new plan of disposal; rather, it is a continuation of the original plan. There is, therefore, no interruption of the application of the requirements in IFRS 5. This amendment is applied prospectively. This amendment does not have any impact on the Company.

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

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 combination 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 if 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 do not have any impact on the Company.

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 and 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; and
- 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 OCI. These amendments do not have any impact on the Company.

IAS 34 Interim Financial Reporting

This amendment clarifies that the required interim disclosures must be either in the interim condensed financial statements, or incorporated by cross-reference between the interim financial statements and wherever they are included within the interim financial report.

The other information within the interim condensed financial statements must be available to users on the same terms as the interim condensed financial statements and at the same time. This amendment must be applied retrospectively and did not have any impact on the Company.

Standards issued but not yet effective up to the date of issuance of the Company's financial statements that are likely to have an impact on the Company are listed below. This listing is of standards and interpretations issued that the Company reasonably expects to be applicable at a future date. The Company intends to adopt those standards when they become effective.

IFRS 2 Classification and Measurement of Share-based Payment Transactions

The IASB issued amendments to *IFRS 2 Share-based Payment* that address three main areas: the effects of vesting conditions on the measurement of a cash-settled share-based payment transaction; the classification of a share-based payment transaction with net settlement features for withholding tax obligations; and accounting where a modification to the terms and conditions of a share-based payment transaction changes its classification from cash settled to equity settled.

Upon adoption, entities are required to apply these amendments without restating prior periods, but retrospective application is permitted if elected for all three amendments and other criteria are met. The amendments 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.

IFRS 9 Financial Instruments

Classification and measurement of financial assets

All financial assets are measured at fair value on initial recognition and adjusted for transaction costs if the instrument is not accounted for at (“**FVTPL**”). Debt instruments are subsequently measured at FVTPL, amortized cost, or fair value through other comprehensive income (“**FVTOCI**”) on the basis of their contractual cash flows and the business model under which the debt instruments are held. There is a fair value option (“**FVO**”) that allows financial assets on initial recognition to be designated as FVTPL if that eliminates or significantly reduces an accounting mismatch. Equity instruments are generally measured at FVTPL. However, entities have an irrevocable option on an instrument-by-instrument basis to present changes in the fair value of non-trading instruments in other comprehensive income (“**OCI**”) without subsequent reclassification to profit or loss.

Classification and measurement of financial liabilities

For financial liabilities designated as FVTPL using the FVO, the amount of change in the fair value of such financial liabilities that is attributable to changes in credit risk must be presented in OCI. The remainder of the change in fair value is presented in profit or loss unless presentation in OCI of the fair value change with respect to the liability’s credit risk would create or enlarge an accounting mismatch in profit or loss. All other IAS 39 Financial Instruments: Recognition and Measurement classification and measurement requirements for financial liabilities have been carried forward into IFRS 9 including the embedded derivative separation rules and the criteria for using the FVO.

Impairment

The impairment requirements are based on an expected credit loss (“**ECL**”) model that replaces the IAS 39 incurred loss model. The ECL model applies to debt instruments accounted for at amortized cost or at FVTOCI, most loan commitments, financial guarantee contracts, contract assets under *IFRS 15 Revenue from Contracts* with Customers, and lease receivables under *IAS 17 Leases*. Entities are generally required to recognize 12-month ECL on initial recognition (or when the commitment or guarantee was entered into) and thereafter as long as there is no significant deterioration in credit risk. However, if there has been a significant increase in credit risk on an individual or collective basis, then entities are required to recognize lifetime ECL. For trade receivables, a simplified approach may be applied whereby the lifetime ECL is always recognized.

The Company previously adopted IFRS 9 (2013) and plans to adopt the amendments to IFRS 9 (2014) at the effective date; the Company is currently in the process of assessing the impact on its consolidated financial statements. The amendments are effective for annual periods beginning on or after January 1, 2018.

Early application is permitted for reporting periods beginning after the issue of IFRS 9 on July 24, 2014 by applying all of the requirements in this standard at the same time. Alternatively, entities may elect to early apply only the requirements for the presentation of gains and losses on financial liabilities designated as FVTPL without applying the other requirements in the standard.

IFRS 15 Revenue from Contracts with Customers

IFRS 15 replaces all existing revenue requirements in IFRS (*IAS 11 Construction Contracts, IAS 18 Revenue, IFRIC 13 Customer Loyalty Programmes, IFRIC 15 Agreements for the Construction of Real Estate, IFRIC 18 Transfers of Assets from Customers and SIC 31 Revenue – Barter Transactions Involving Advertising Services*) and applies to all revenue arising from contracts with customers unless the contracts are in the scope of other standards such as IAS 17. Its requirements also provide a model for the recognition and measurement of gains and losses on disposal of certain non-financial assets including property, equipment, and intangible assets. This standard outlines the principles an entity must apply to measure and recognize revenue. The core principle is that an entity will recognize revenue at an amount that reflects the consideration to which the entity expects to be entitled in exchange for transferring goods or services to a customer.

The principles in IFRS 15 will be applied using a five-step model:

1. Identify the contract(s) with a customer
2. Identify the performance obligations in the contract
3. Determine the transaction price
4. Allocate the transaction price to the performance obligations in the contract
5. Recognize revenue when (or as) the entity satisfies a performance obligation

The standard requires entities to exercise judgment and taking into consideration all of the relevant facts and circumstances when applying each step of the model to contracts with their customers. The standard also specifies how to account for the incremental costs of obtaining a contract and the costs directly related to fulfilling a contract. Application guidance is provided in IFRS 15 to assist entities in applying its requirements to certain common arrangements including licences of intellectual property, warranties, rights of return, principal-versus-agent considerations, options for additional goods or services, and breakage. The new standard will apply for annual periods beginning on or after January 1, 2018. Entities can choose to apply the standard using either a full retrospective approach with some limited relief provided or a modified retrospective approach. Early application is permitted and must be disclosed.

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

The scope of IFRS 16 includes leases of all assets with certain exceptions. A lease is defined as a contract or part of a contract that conveys the right to use an asset (the underlying asset) for a period of time in exchange for consideration. IFRS 16 requires lessees to account for all leases under a single on-balance sheet model in a similar way to finance leases under IAS 17. The standard includes two recognition exemptions for lessees: leases of 'low-value' assets (i.e., personal computers) and short-term leases (i.e., leases with a lease term of 12 months or less). At the commencement date of a lease, a lessee will recognize a liability to make lease payments (i.e., the lease liability) and an asset representing the right to use the underlying asset during the lease term (i.e., the right-of-use asset). Lessees will be required to separately recognize the interest expense on the lease liability and the depreciation expense on the right-of-use asset. Lessees will be required to remeasure the lease liability upon the occurrence of certain events (i.e., a change in the lease term, or a change in future lease payments resulting from a change in an index or rate used to determine those payments). The lessee will generally recognise the amount of the remeasurement of the lease liability as an adjustment to the right-of-use asset. Lessor accounting is substantially unchanged from today's accounting under IAS 17. Lessors will continue to classify all leases using the same classification principle as in IAS 17 and distinguish between two types of leases: operating and finance leases. The new standard will apply for annual periods beginning on or after January 1, 2019. A lessee can choose to apply the standard using either a full retrospective or a modified retrospective transition approach. The standard's transition provisions permit certain reliefs. Early application is permitted, but not before an entity applies 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.

IAS 7 Statement of Cash Flows

The amendments to *IAS 7 Statement of Cash Flows* are part of the IASB's Disclosure Initiative and require an entity to provide disclosures that enable users of financial statements to evaluate changes in liabilities arising from financing activities including both changes arising from cash flows and non-cash changes. The amendments are effective for annual periods beginning on or after January 1, 2017, 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.

IAS 12 Income taxes

The IASB issued the amendments to *IAS 12 Income Taxes* to clarify the accounting for deferred tax assets for unrealized losses on debt instruments measured at fair value. The amendments clarify that an entity needs to consider whether tax law restricts the sources of taxable profits against which it may make deductions on the reversal of that deductible temporary difference. Furthermore, the amendments provide guidance on how an entity should determine future taxable profits and explains in which circumstances taxable profit may include the recovery of some assets for more than their carrying amount. The amendments are effective for annual periods beginning on or after January 1, 2017. Entities are required to apply the amendments retrospectively. However, on initial application of the amendments, the change in the opening equity of the earliest comparative period may be recognized in opening retained earnings (or in another component of equity, as appropriate) without allocating the change between opening retained earnings and other components of equity. Entities applying this relief must disclose that fact. Early application is permitted. If an entity applies the amendments for an earlier period, it must disclose that fact.

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.

7. 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 certify, among other things, 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'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 may not prevent or detect all misstatements because of inherent limitations. Additionally, projections of any evaluation of effectiveness in future periods are subject to the risk that controls may become inadequate because of changes in conditions or deterioration in the degree of compliance with the Company's policies and procedures. During the three months and year ended December 31, 2016, 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 has evaluated and concluded that there are no material weaknesses or significant deficiencies in the design or effectiveness of ICFR as at December 31, 2016.

During the fourth quarter of 2016, 250 controls were tested over the 585 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, 2016.

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 the Company under securities legislation is recorded, processed, summarized, and reported within the time period specified in securities legislation.

Based on the Company's evaluation, which was 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, 2016.

During 2016 the Board of Directors appointed a new Chief Financial Officer who assumed the position as of December 1, 2016. One of the primary duties of the Chief Financial Officer is to maintain and continue to strengthen the Company's ICFR.

8. 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 and Cajua fields is 60%. However, this participation may change monthly as a function of the PAP formula stipulated in the Quifa Association Contract.

Carrizales Field (Cravoviejo Block)

On April 27, 2013, 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 Cravoviejo E&P 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.

Zopilote Field (Cravoviejo Block)

In April 2015, the exploitation area of the Zopilote field reached five million barrels in accumulated production of oil, activating the ANH rights on additional PAP pursuant to the Cravoviejo E&P contract. According to the contract terms, this additional participation share from the Zopilote 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 ANH relating to the interpretation of the high-price participation clause. These contracts require high-price participation payments to be paid to the ANH once an exploitation area within a contracted area has cumulatively produced five million or more barrels of oil. The disagreement 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 E&P 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 in 2013 and which is the only one for which an arbitration process has been initiated. However, the arbitration process for Corcel was suspended at the time the Company acquired Petrominerales.

As at December 31, 2016, the amount under arbitration is approximately $195 million plus related interest of $45 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 U.S. dollars, 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 E&P contracts (excluding Corcel). The Company believes that it has a strong position with respect to the high-price participation based on legal interpretation of the contracts and technical data available. However, in accordance with IFRS 3, to account for business acquisitions the Company is required to and has recorded a liability for such contingencies as of the date of acquisition, even though the Company believes the disagreement will be resolved in favour of the Company. The Company does not disclose the amount recognized as required by paragraphs 84 and 85 of IAS 37 on the grounds that this would be prejudicial to the outcome of the dispute resolution.

Update on Environmental Permits

On October 13, 2016, the National Authority of Environmental Licences ("**ANLA**") granted the modification to the Environmental Licence for "La Creciente" field. This authorization allowed the Company to:

- Increase the Early Production Facilities;
- Build new roads across the Early Production Facilities; and
- Inject produced water in the "Cienaga de Oro" formation in order to increase gas production.

On October 7, 2016, the ANLA granted the Environmental Licence for the "Canaguaro" field. This authorization allowed the Company to:

- Build new roads across the wells and production facilities;
- Construct new areas for well sites, production facilities, and pipelines; and
- Obtain environmental permits to operate the field.

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, boe has been expressed using the Colombian conversion standard of 5.7 Mcf: 1 bbl required by the Colombian Ministry of Mines and Energy. For all natural gas reserves in Peru, boe has 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.

9. 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 risks that might affect the oil and gas industry generally or the Company specifically. These include, but are not limited to:

- Volatility in market prices for oil and natural gas;
- A continued depressed oil and natural gas price environment with the potential of further decline;
- The potential ineffectiveness or unintended consequences of the Company's ongoing cost and capital expenditure reduction;
- The effect of ratings downgrades on the Company's business and operations;
- Uncertainties associated with estimating oil and natural gas reserves;
- The expiration of the Company's exploration and exploitation contracts and the costs associated therewith;
- Uncertainty over the ability to add reserves through exploration, acquisition, or development activities to mitigate the effect of reserves and production decline over time;
- The availability of drilling and related equipment, transportation, power, and technical support in the areas where the Company's activities will be conducted;
- The costs associated with, and availability of funds for, abandoning and reclaiming wells, facilities, and pipelines that the Company uses for production of oil and gas reserves;
- The costs of compulsory work programs under the Company's exploration contracts and the penalties associated with failing to meet them;
- The impact of operating costs on net revenue;
- Uncertainties relating to the availability and costs of financing needed in the future;
- Delays in obtaining required environmental and other licences;
- The effect of global financial conditions on the Company's operations and ability to raise capital;
- Competition in the oil and gas industry for capital, acquisitions of reserves, undeveloped land, and skilled personnel, among other things;
- Disruptions in, or the increase of costs associated with, the transportation of hydrocarbons;
- The direct and indirect costs associated with labour disruptions in or around the Company's operations;
- The possibility of litigation relating to labour, health and safety matters, environmental matters, regulatory, tax, and administrative proceedings, governmental investigations, arbitration, and contractual claims and disputes, the results of which are difficult to predict;
- The effect and costs of environmental regulation in the countries in which the Company operates;
- Fluctuations in foreign exchange or interest rates and stock market volatility;
- The possibility of disproportionate effects and costs associated with the concentration of a majority of the Company's producing properties and leases in the Llanos Basin in eastern Colombia;
- The difficulty of impossibility of enforcing judgments granted by a court in Canada against the assets of the Company or the directors and officers of the Company residing outside of Canada;
- The lack of assurance that restrictions on repatriation of earnings from Colombian subsidiaries will not be imposed in the future;
- The possibility that the Company may be unable to declare and pay dividends on its Common Shares;
- The possibility that if certain contingencies occur, they could have a material adverse effect on the Company's business, results of operations, and financial condition; and/or

- The possible dilution of the Company's equity interest in Pacific Infrastructure.

Readers are cautioned that the foregoing list of factors is not exhaustive. The Company's Annual Information Form ("**AIF**") for the period ended December 31, 2016 and dated March 15, 2017 contains a more comprehensive discussion of the risks and uncertainties that could have an effect on the business and operations of the Company. The AIF is available at www.sedar.com and readers are urged to read the discussion in its entirety.

10. Abbreviations

The following abbreviations are frequently used in the Company's MD&A.

1P	Proved reserves
2P	Proved reserves + Probable reserves
bbl	Barrels
bbl/d	Barrels per day
boe	Barrels of oil equivalent
boe/d	Barrels of oil equivalent per day
Mbbl	Thousand barrels
Mbbl/d	Thousand barrels per day
Mboe	Thousand barrels of oil equivalent
Mboe/d	Thousand barrels of oil equivalent per day
MMbbl	Million barrels
MMbbl/d	Million barrels of oil per day
MMboe	Million barrels of oil equivalent
WTI	West Texas Intermediate index