MANAGEMENT'S REPORT

Management is responsible for the reliability and integrity of the consolidated financial statements, the notes to the consolidated financial statements, and other financial information presented elsewhere in this annual report.

The consolidated financial statements were prepared by management in accordance with International Financial Reporting Standards. Since a precise determination of many assets and liabilities is dependent on future events, the timely preparation of financial statements requires that management make estimates and assumptions and use judgment. When alternative accounting methods exist, management has chosen those that it deems most appropriate in the circumstances.

PricewaterhouseCoopers LLP were appointed by the Company's shareholders to express an audit opinion on the consolidated financial statements. Their examination included such tests and procedures as they considered necessary to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

The Board of Directors is responsible for overseeing that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through the Finance & Audit Committee. The Finance & Audit Committee recommends appointment of the external auditors to the Board, evaluates their independence and approves their fees. The Finance & Audit Committee meets regularly with management and the external auditors to oversee that management's responsibilities are properly discharged, to review the consolidated financial statements and recommend that the consolidated financial statements be presented to the Board for approval. The external auditors have full and unrestricted access to the Finance & Audit Committee to discuss their audit and their findings.

David R. Taylor
President, Chief Executive Officer

Kenneth G. Pinsky
Chief Financial Officer

March 5, 2018

March 5, 2018

Independent Auditor's Report

To the Shareholders of Parex Resources Inc.

We have audited the accompanying consolidated financial statements of Parex Resources Inc. and its subsidiaries, which comprise the consolidated balance sheets as at December 31, 2017 and December 31, 2016 and the consolidated statements of comprehensive income (loss), changes in equity and cash flows for the years then ended, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements
Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility
Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Parex Resources Inc. and its subsidiaries as at December 31, 2017 and December 31, 2016 and their financial performance and their cash flows for the years then ended in accordance with International Financial Reporting Standards.

PricewaterhouseCoopers LLP

Chartered Professional Accountants
Calgary, Alberta

CONSOLIDATED FINANCIAL STATEMENTS
Consolidated Balance Sheets

As at (thousands of United States dollars)	NOTE		December 31, 2017		December 31, 2016
ASSETS					
Current assets					
Cash		**$**	**235,042**	$	149,246
Accounts receivable	**5**		**79,152**		46,019
Prepaids and other current assets			**1,828**		2,502
Crude oil inventory	**6**		**3,038**		2,834
		$	**319,060**	$	200,601
Deferred tax asset	**16**		**20,815**		17,324
Goodwill	**10**		**73,452**		73,452
Exploration and evaluation	**7**		**107,144**		101,024
Property, plant and equipment	**8**		**601,437**		526,270
		$	**1,121,908**	$	918,671
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities					
Accounts payable and accrued liabilities		**$**	**103,509**	$	86,313
Derivative financial instruments	**21**		**116**		1,704
Current income tax payable	**16**		**42,266**		8,404
Current portion of decommissioning and environmental liabilities	**13**		**9,768**		10,890
			155,659		107,311
Other long-term liabilities	**12**		**4,718**		1,652
Decommissioning and environmental liabilities	**13**		**42,912**		40,256
Deferred tax liability	**16**		**30,345**		55,660
			233,634		204,879
Shareholders' equity					
Share capital	**14**		**836,166**		822,227
Contributed surplus			**52,431**		42,208
(Deficit)			**(323)**		(150,643)
			888,274		713,792
		$	**1,121,908**	$	918,671

Commitments and Contingencies (note 23)

See accompanying Notes to the Consolidated Financial Statements
Approved by the Board:

Paul Wright
Director

Ron Miller
Director

Consolidated Statements of Comprehensive Income (Loss)

For the year ended December 31, (thousands of United States dollars, except per share amounts)	NOTE	2017	2016
Oil and natural gas sales		$ 659,407	$ 445,488
Royalties		(58,540)	(34,327)
Revenue		600,867	411,161
Commodity risk management contracts (loss)	21	(1,210)	(10,666)
		599,657	400,495
Expenses			
Production		69,169	53,250
Transportation		141,475	130,930
Purchased oil		5,653	25,109
General and administrative		34,089	30,814
Legal settlement	23	15,000	—
Impairment of exploration and evaluation assets	7	35,621	69,880
Impairment of property, plant and equipment	8	—	9,597
Equity settled share-based compensation	14	18,381	12,818
Cash settled share-based compensation	15	8,479	12,927
Depletion, depreciation and amortization	8	98,738	115,777
Foreign exchange loss		462	1,485
		427,067	462,587
Finance (income)	11	(7,371)	(1,260)
Finance expense	11	9,669	10,283
Net finance expense		2,298	9,023
Income (loss) before income taxes		170,292	(71,115)
Income tax expense (recovery)			
Current tax expense	16	44,020	5,628
Deferred tax (recovery)	16	(28,806)	(30,299)
		15,214	(24,671)
Net income (loss) and comprehensive income (loss) for the year		$ 155,078	$ (46,444)
Basic net income (loss) per common share	17	$ 1.01	$ (0.31)
Diluted net income (loss) per common share	17	$ 0.99	$ (0.31)

See accompanying Notes to the Consolidated Financial Statements

Consolidated Statements of Changes in Equity

For the year ended December 31, (thousands of United States dollars)		**2017**		2016
Share Capital				
Balance, beginning of year	**$**	**822,227**	$	812,737
Issuance of common shares under share-based compensation plans		**16,668**		9,490
Repurchase of shares		**(2,729)**		—
Balance, end of year	**$**	**836,166**	$	822,227
Contributed Surplus				
Balance, beginning of year	**$**	**42,208**	$	33,388
Share-based compensation		**18,381**		12,818
Options and RSUs exercised		**(6,762)**		(3,998)
Contributed surplus attributed to DSUs transferred to cash settled liability		**(1,396)**		—
Balance, end of year	**$**	**52,431**	$	42,208
(Deficit)				
Balance, beginning of year	**$**	**(150,643)**	$	(104,199)
Net income (loss) for the year		**155,078**		(46,444)
Repurchase of shares		**(4,758)**		—
Balance, end of year		**(323)**		(150,643)
	$	**888,274**	$	713,792

See accompanying Notes to the Consolidated Financial Statements

Consolidated Statements of Cash Flows

For the year ended December 31, (thousands of United States dollars)	NOTE	2017	2016
Operating activities			
Net income (loss)		**$ 155,078**	$ (46,444)
Add (deduct) non-cash items			
Depletion, depreciation and amortization	**8**	**98,738**	115,777
Non-cash finance (income) expense	**11**	**(432)**	1,831
Equity settled share-based compensation expense	**14**	**18,381**	12,818
Cash settled share-based compensation expense	**15**	**8,479**	12,927
Deferred tax (recovery)	**16**	**(28,806)**	(30,299)
Impairment of exploration and evaluation assets	**7**	**35,621**	69,880
Impairment of property, plant and equipment	**8**	**—**	9,597
Unrealized foreign exchange (gain) loss		**3,003**	(354)
Unrealized (gain) on commodity risk management contracts	**21**	**(1,178)**	3,859
Abandonment costs paid	**13**	**(1,391)**	(178)
Share appreciation rights paid	**15**	**(7,965)**	(5,283)
Funds flow provided by operations		**279,528**	144,131
Net change in non-cash working capital	**18**	**5,501**	9,898
Cash provided by operating activities		**285,029**	154,029
Investing activities			
Property, plant and equipment expenditures	**8**	**(135,583)**	(59,519)
Exploration and evaluation expenditures	**7**	**(71,066)**	(48,178)
Property acquisitions	**9**	**(5,697)**	(4,025)
Net change in non-cash working capital	**18**	**11,152**	5,988
Cash (used in) investing activities		**(201,194)**	(105,734)
Financing activities			
Issuance of common shares under share-based compensation plans	**14**	**9,906**	5,492
Common shares repurchased	**14**	**(7,487)**	—
Cash provided by financing activities		**2,419**	5,492
Increase in cash for the year		**86,254**	53,787
Impact of foreign exchange on foreign currency-denominated cash balances		**(458)**	636
Cash, beginning of year		**149,246**	94,823
Cash, end of year		**$ 235,042**	$ 149,246

Supplemental Disclosure of Cash Flow Information (note 18)
See accompanying Notes to the Consolidated Financial Statements

For the year ended December 31, 2017
(Tabular amounts in thousands of United States dollars, unless otherwise stated. Amounts in text are in United States dollars, unless otherwise stated.)

1. Corporate Information

Parex Resources Inc. and its subsidiaries ("Parex" or "the Company") are in the business of the exploration, development, production and marketing of oil and natural gas in Colombia.

Parex Resources Inc. is a publicly traded Company, incorporated and domiciled in Canada. Its registered office is at 2400, 525-8th Avenue S.W., Calgary, Alberta T2P 1G1. The Company was incorporated on August 17, 2009, pursuant to the Business Corporations Act (Alberta).

The consolidated financial statements were approved and authorized for issuance by the Board of Directors on March 5, 2018.

2. Basis of Preparation, Critical Accounting Estimates and Judgements

a) Statement of compliance

These consolidated financial statements have been prepared in accordance with IFRS, as issued by the International Accounting Standard Boards ("IASB").

The policies applied in these consolidated financial statements are based on IFRS issued and outstanding as of March 5, 2018, the date the Board of Directors approved the consolidated financial statements.

b) Basis of measurement

The consolidated financial statements have been prepared under the historical cost convention except for derivative financial instruments and share-based compensation transactions which are measured at fair value. The methods used to measure fair values are discussed in note 4 - Determination of Fair Values.

c) Use of management estimates, judgments and measurement uncertainty

The timely preparation of the consolidated financial statements requires that management make estimates and use judgment regarding the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as at the date of the consolidated financial statements. Accordingly, actual results could differ from estimated amounts as future confirming events occur. Significant estimates and judgments made by management in the preparation of these consolidated financial statements are outlined below:

(i) Depletion, depreciation and reserves

Depletion is based on the proved plus probable reserves as evaluated in accordance with National Instrument 51-101, *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") and incorporating the estimated future cost of developing and extracting those. The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates are based on current production forecasts, prices and economic conditions. As circumstances change and additional data becomes available, reserve estimates may also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions of reserve estimates are often required due to changes in well performance, prices, economic conditions and governmental regulations.

Although every reasonable effort is made to determine that reserve estimates are accurate, reserve estimation is an inferential science. As a result, subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices and reservoir performance. Such revisions can be either positive or negative. Changes in reserve estimates impact the financial results of the Company as reserves and estimated future development costs are used to calculate depletion and are also used in measuring fair value less costs of disposal of property, plant and equipment for impairment calculations (see note 8).

(ii) Determination of cash-generating units ("CGU")

The determination of CGUs requires judgment in defining a group of assets that generate cash inflows that are largely independent of the cash inflows from other assets or groups of assets. CGUs are determined by similar geological structure, shared infrastructure, geographical proximity, commodity type, similar exposure to market risks and materiality.

(iii) Exploration and evaluation ("E&E")

The decision to transfer assets from E&E to property, plant and equipment ("PP&E") is primarily based on the estimated proved plus probable reserves used in the determination of an area's technical feasibility and commercial viability (see note 7).

(iv) Decommissioning and environmental liabilities

Decommissioning and restoration costs will be incurred by the Company at the end of the operating life of certain of its assets. The ultimate decommissioning and restoration costs are uncertain and cost estimates can vary in response to many factors including changes to relevant legal and regulatory requirements, the emergence of new restoration techniques or experience at other production sites. The expected timing and amount of expenditure can also change in response to changes in reserves, laws and regulations or their interpretation, the timing and likelihood of the settlement of the obligation, discount rates, and future interest rates. As a result, there could be significant adjustments to the provisions established which would affect future financial results. The Company uses a risk-free discount rate.

Liabilities for environmental costs are recognized in the period in which they are incurred, normally when the asset is developed and the associated costs can be estimated. These liabilities are in addition to the decommissioning liabilities due to government regulations that require the Company to perform additional mitigation against the environmental issues attributed to water usage and deforestation from oil and gas activities performed. In addition, the timing of expected settlement of the environmental liabilities differs from the timing of expected settlement of the decommissioning liabilities. Refer to note 13 – Decommissioning and Environmental Liabilities.

(v) Impairment indicators and discount rate

The recoverable amounts of CGUs and individual assets have been determined as the greater of either an asset's or CGU's value in use or fair value less costs of disposal. These calculations require the use of estimates and assumptions and are subject to changes as new information becomes available including information on future commodity prices, quantity of reserves and discount rates as well as future development and operating costs. It is reasonably possible that the commodity price assumptions may change, which may impact the estimated life of the oil and natural gas reserves and the recoverable economical reserves and may require a material adjustment to the carrying value of oil and natural gas assets. The Company monitors internal and external indicators of impairment relating to its property, plant and equipment, and exploration and evaluation assets. Refer to note 7 – Exploration and Evaluation Assets, note 8 – Property, Plant and Equipment and note 11 – Goodwill.

(vi) Share-based compensation

Compensation costs accrued for under the Company's Stock Option plan and Share Appreciation Right ("SAR") plan are subject to the estimation of what the ultimate payout will be using the Black-Scholes pricing model which is based on significant assumptions such as the future volatility of the market price of Parex shares and expected term of the issued stock option or SAR. Compensation costs accrued for under the Company's Restricted Share Unit ("RSU') plan pursuant to which RSUs and Performance Share Units ("PSUs") may be issued, Deferred Share Unit ("DSU") plan and Cash Settled Restricted Share Units ("CRSU") plan are measured at fair value based on the market price of Parex shares on the date of issuance. Refer to note 14 - Share Capital and note 15 - Cash Settled Incentive Plans.

(vii) Derivative financial asset/liability

The estimated fair value of derivative instruments and resulting derivative assets and liabilities depends on estimated forward prices and volatility in those prices and by their nature are subject to measurement uncertainty.

(viii) Income taxes

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change and interpretation. As such, income taxes are subject to measurement uncertainty. The Company follows the liability method for calculating deferred taxes. Assessing the recoverability of deferred tax assets requires the Company to make significant estimates related to the expectations of future cash flows from operations and the application of existing tax laws. To the extent that future cash flows and taxable income differ significantly from estimates, the ability of the Company to realize the deferred tax assets and liabilities recorded at the balance sheet date could be impacted. Additionally, changes in tax laws could limit the ability of the Company to obtain tax deductions in the future.

(ix) Business combinations, corporate and property acquisitions

Business combinations, corporate and property acquisitions are accounted for using the acquisition method of accounting whereby the assets acquired and the liabilities assumed are recorded at fair values. The determination of fair value often requires management to make assumptions and estimates about future events. The fair value of property, plant and equipment recognized in a business combination, corporate or property acquisition is based on market values. The market value of property, plant and equipment is the estimated amount for which PP&E could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm's length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The market value of oil and natural gas interests (included in PP&E) are estimated with reference to the discounted cash flows expected to be derived from oil and natural gas production based on externally prepared reserve reports. The market value of E&E assets are estimated with reference to the market values of current arm's length transactions in comparable locations. Assumptions are also required to determine the fair value of decommissioning obligations associated with the properties. Changes in any of these assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities and goodwill (or gain from a bargain purchase) in the acquisition equation. Future net earnings can be affected as a result of changes in future depletion and depreciation, asset impairment or goodwill impairment.

3. Summary of Significant Accounting Policies

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

a) Consolidation

The consolidated financial statements include the accounts of the Company and all of its subsidiaries at December 31, 2017. The principal operating subsidiaries and their activities are:

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

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

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

b) Foreign currency translation

(i) Functional and presentation currency

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

(ii) Transactions and balances

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

c) Financial instruments

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

Loans and receivables

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

Other financial liabilities

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

Derivative instruments

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

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

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

d) Capital assets

(i) Exploration and evaluation

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

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

(ii) Property, plant and equipment

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

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

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

e) Impairment of long-term assets

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

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

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

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

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in comprehensive income (loss).

The recoverable amount of goodwill is determined as the fair value less costs of disposal using a discounted cash flow method. Goodwill is evaluated at the Colombia segment level as business combinations giving rise to goodwill do not have specifically identifiable benefits to any one CGU.

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

f) Crude oil inventory and overlift oil volumes

Crude oil inventory consists of crude oil in transit at the balance sheet date and is valued at the lower of cost, using the weighted average cost method, and net realizable value. Costs include direct and indirect expenditures incurred in bringing the crude oil to its existing condition and location. The liability for overlift oil volumes is valued based on the Brent oil price at the balance sheet date. Sales revenue is subsequently recorded at the Brent oil price once the overlifted pipeline volumes are returned. A gain/loss on overlifted oil volumes is recorded on the difference between the original liability and the revenue recorded on the returned barrels.

g) Purchased oil

Purchased oil includes costs to buy third party oil and accruals for overlifted oil volumes. The costs for third party oil are initially recorded in inventory until the crude oil title is transferred. The costs for overlifted oil volumes are originally recorded as an accrued liability until the volumes are returned.

h) Goodwill

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

i) Revenue recognition

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

j) Equity settled share-based compensation

The Company has an incentive stock option plan and a restricted unit plan pursuant to which the Company may issue Restricted Share Units ("RSUs") and Performance Share Units ("PSUs") for certain employees, officers and directors as described in note 14. The Company records share-based compensation expense using the fair value method. The fair value of an option granted is calculated at the grant date using the Black-Scholes pricing model, and expensed over the vesting period of the option. The fair value of each RSU and PSU granted is calculated using the market price of Parex shares on the date of issuance, and expensed over the vesting period of the RSU and PSU. The Company determines an appropriate forfeiture rate by examining the history of its forfeitures. The Company records the cumulative share-based compensation as contributed surplus. When options, RSUs or PSUs are exercised, contributed surplus is reduced and share capital is increased by the amount of accumulated share-based compensation for the exercised security. Any consideration received on the exercise of stock options, RSUs or PSUs is credited to share capital.

PSUs may be granted with certain performance measures, specified at the grant date as determined by the Company's Board of Directors. Based upon the achievement of the performance measures, a pre-determined adjustment factor of between 0-2x is applied to PSUs eligible to vest at the end of the performance period. The expense recognized over the vesting period of PSUs is the fair value of the PSUs with an estimated adjustment factor. If the actual final adjustment factor is higher than estimated at grant, additional expense is recognized on vesting for the incremental fair value. Upon the exercise of the options, RSUs and PSUs consideration paid together with the amount previously recognized in contributed surplus is recorded as an increase to share capital.

k) Cash settled share-based compensation

The Company has a share appreciation rights plan for certain employees of Parex Colombia as described in note 15. Obligations for payments of cash under the foreign subsidiaries' SARs plan are accrued as compensation expense over the vesting period based on the fair value of SARs, subject to appreciation limits specified in the plan. The fair value of SARs is measured using the Black-Scholes pricing model. In accordance with the fair value method, increases or decreases in the fair value of the SARs result in a corresponding change in the recorded liability. The accrued compensation for a right that is forfeited is adjusted by decreasing compensation cost in the period of forfeiture.

The Company has a Cash Settled Restricted Share Unit ("CRSUs") plan which allows the Company to issue CRSUs to certain employees of Parex Colombia as described in note 15. Obligations for payments of cash under the foreign subsidiaries' CRSUs plan are accrued as compensation expense over the vesting period based on the fair value of CRSUs. The fair value of CRSUs is equal to the market price of the Company's common shares at the valuation date. In accordance with the fair value method, increases or decreases in the fair value of the CRSUs result in a corresponding change in the recorded liability. The accrued compensation for a right that is forfeited is adjusted by decreasing compensation cost in the period of forfeiture. The CRSUs liability cannot be settled by the issuance of common shares.

In the current year the Company amended the terms of its Deferred Share Unit ("DSU") plan which allows the Company to issue DSUs to certain non-employee directors of Parex Resources Inc, as described in note 15. Previously DSUs were settled in shares or cash at the discretion of the Company. Going forward the DSUs will be settled in cash and the DSUs liability cannot be settled by the issuance of common shares. As DSUs vest immediately on issuance, obligations for payments of cash under the DSUs plan are accrued as compensation expense immediately on issuance based on the fair value of the DSUs. The fair value of DSUs at each reporting period is equal to the market price of the Company's common shares at the valuation date. In accordance with the fair value method, increases or decreases in the fair value of the DSUs result in a corresponding change in the recorded liability. The accrued compensation for a unit that is forfeited is adjusted by decreasing compensation cost in the period of forfeiture.

l) Provisions

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

m) Decommissioning and environmental liabilities

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

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

n) Operating Segments

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

o) Finance income and expense

Finance expense comprises interest expense on borrowings, bank taxes, accretion on provisions, net wealth tax, impairment losses recognized on financial assets and gains/losses on overlifted oil volumes. Finance income comprises interest earned on cash and other income and gains on property acquisitions.

p) Cash

Cash is comprised of cash and other short-term highly liquid investments with maturities less than 3 months held in chartered banks in Canada and recognized financial institutions abroad with BBB+ credit ratings or higher.

q) Income taxes

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

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

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

r) Per share information

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

s) New standards and interpretations not yet adopted

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

IFRS 15 Revenue from Contracts with Customers - In April 2016, the IASB issued its final amendments to IFRS 15 Revenue from Contracts with Customers ("IFRS 15"), which replaces IAS 18 Revenue, IAS 11 Construction Contracts, and related interpretations. IFRS 15 provides a single, principles-based five-step model to be applied to all contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive when control is transferred to the purchaser. Disclosure requirements have also been expanded. The standard is required to be adopted either retrospectively or using a modified retrospective approach for annual periods beginning on or after January 1, 2018, with earlier adoption permitted.

The Company has reviewed its revenue streams and underlying contracts with customers. It has been concluded that the adoption of IFRS 15 will not have a material impact on the Company's net income and financial position. However, the Company will expand the disclosures in the notes to its financial statements as prescribed by IFRS 15, including disclosing the Company's disaggregated revenue streams by product type.

IFRS 9 Financial Instruments - In July 2014, the IASB completed the final elements of IFRS 9 Financial Instruments ("IFRS 9"). The standard supersedes earlier versions of IFRS 9 and completes the IASB's project to replace IAS 39 Financial Instruments: Recognition and Measurement ("IAS 39"). IFRS 9 introduces a single approach to determine whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. For financial liabilities, IFRS 9 retains most of the requirements of IAS 39; however, where the fair value option is applied to financial liabilities, any change in fair value resulting from an entity's own credit risk is recorded in other comprehensive income rather than the statement of income. The Company has determined that adoption of IFRS 9 will not result in changes to the classification of the Company's financial assets or the classification of the Company's financial liabilities. The Company has also determined there will not be any material changes in the measurement and carrying values of the Company's financial instruments as a result of the adoption of IFRS 9.

In addition, IFRS 9 introduces a new expected credit loss model for calculating impairment of financial assets, replacing the incurred loss impairment model required by IAS 39. The Company has determined that the new impairment model will not result in material changes to the valuation of its financial assets on adoption of IFRS 9. IFRS 9 also contains a new model to be applied for hedge accounting. The Company does not currently apply hedge accounting to its risk management contracts and does not currently intend to apply hedge accounting to any of its existing risk management contracts on adoption of IFRS 9. The standard will come into effect for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. IFRS 9, as well as consequential amendments to IFRS 7 Financial Instruments: Disclosures ("IFRS 7"), will be applied on a retrospective basis by the Company on January 1, 2018.

IFRS 16 Leases - In January 2016, the IASB issued IFRS 16 Leases ("IFRS 16"), which replaces IAS 17 Leases and IFRIC 4 Determining Whether an Arrangement Contains a Lease. IFRS 16 requires the recognition of lease assets and liabilities on the balance sheet for most leases, where the entity is acting as a lessee. For lessees applying IFRS 16, the dual classification model of leases as either operating leases or finance leases no longer exists, effectively treating all leases as finance leases. Certain short-term leases (less than 12 months) and leases of low-value assets are exempt from the balance sheet recognition requirements, and may continue to be treated as operating leases. Lessors will continue with the dual classification model for leases and the accounting for lessors remains virtually unchanged.

The standard will come into effect for annual periods beginning on or after January 1, 2019, with earlier adoption permitted if the entity is also applying IFRS 15. IFRS 16 is required to be adopted either retrospectively or using a modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect as an adjustment to opening retained earnings and applies the standard prospectively.

IFRS 16 will be applied by the Company on January 1, 2019. The Company is currently engaging and educating stakeholders and is implementing corporate processes to ensure contract completeness to identify leases. Identifying, gathering and analyzing contracts impacted by the adoption of the new standard will extend into 2018. Although the transition approach on adoption has not yet been determined, it is anticipated that the adoption of IFRS 16 will have a material impact on the Company's financial statements.

4. Determination of Fair Values

A number of the Company’s accounting policies and disclosures require the determination of fair value for financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the methods below. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

a) PP&E and intangible exploration assets

The fair value of PP&E and intangible exploration assets are determined if there are indicators of impairment. The fair value of PP&E is the estimated amount for which PP&E could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm’s-length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The fair value of oil and natural gas assets (included in PP&E) is estimated with reference to the discounted cash flows expected to be derived from oil and natural gas production based on externally prepared reserve reports. The risk-adjusted discount rate is specific to the asset with reference to general market conditions. All level 3 inputs.

b) Cash, accounts receivable, and accounts payable and accrued liabilities

The fair value of cash, accounts receivable and accounts payable and accrued liabilities is estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At December 31, 2017 and 2016 the fair value of these balances approximated their carrying value due to their short-term to maturity.

c) Stock options

The fair value of stock options is measured using the Black-Scholes pricing model. Measurement inputs include the share price on measurement date, exercise price of the option, expected future share price volatility, weighted average expected life of the instruments (based on historical experience and general option-holder behavior), expected dividends and the risk-free interest rate (based on Government of Canada Bonds) for the relevant expected life as described in note 14.

d) Share appreciation rights

The fair value of SARs is measured using the Black-Scholes pricing model. Measurement inputs include the share price on each balance sheet date, expected future share price volatility, weighted average expected life of the instruments (based on historical experience and general SAR-holder behavior), expected dividends and the risk-free interest rate (based on Government of Canada Bonds) for the relevant expected life as described in note 15.

e) Restricted share units, performance share units, cash settled restricted share units and deferred share units

The fair value of stock RSUs, PSUs, CRSUs and DSUs are measured based on the market price of Parex shares on the valuation date. Refer to note 14 and 15.

f) Derivative financial asset /liability

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

5. Accounts Receivable

	December 31, 2017	December 31, 2016
Trade receivables	**$ 28,366**	$ 15,469
Colombia income taxes receivable	**36,843**	19,810
Value added taxes (VAT)	**13,943**	10,740
	$ 79,152	$ 46,019

Trade receivables consist primarily of oil sale receivables related to the Company's oil sales. Colombia income tax receivable is a result of withholding tax incurred on Colombia oil sales and tax installments. The balance can either be received in cash or applied to Colombian cash income tax payable. VAT receivable is $13.9 million as at December 31, 2017 (December 31, 2016 - $10.7 million) and is recoverable in 2018. All accounts receivable are expected to be received within twelve months and are thus recognized as current assets.

6. Inventory

	December 31, 2017	December 31, 2016
Crude oil inventory	**$ 3,038**	$ 2,834

Crude oil inventory consists of crude oil in transit at the balance sheet date and is valued at the lower of cost, using the weighted average cost method, and net realizable value. Costs include direct and indirect expenditures incurred in bringing the crude oil to its existing condition and location. During 2017 $2.8 million (December 31, 2016 - $3.2 million) of produced crude oil inventory cost was expensed to the consolidated statement of comprehensive income (loss). Purchased crude oil is sold immediately. The cost associated with purchased oil is shown in the consolidated statement of comprehensive income (loss) as purchased oil expense.

7. Exploration and Evaluation Assets

Cost	
Balance at December 31, 2015	$ 121,354
Additions	48,178
Changes in decommissioning liability	1,372
Exploration and evaluation impairment	(69,880)
Balance at December 31, 2016	**$ 101,024**
Additions	71,066
Transfers to PP&E	(29,757)
Changes in decommissioning liability	432
Exploration and evaluation impairment	(35,621)
Balance at December 31, 2017	**$ 107,144**

Additions and Transfers

E&E assets consist of the Company's exploration projects which are pending either the determination of proved or probable reserves or impairment. During the year ended December 31, 2017 additions of $71.1 million (year ended December 31, 2016 - $48.2 million) represent the Company's share of costs incurred on E&E assets during the period. During the year ended December 31, 2017 $29.8 million of E&E assets were transferred to PP&E mainly related to the Aguas Blancas Block (year ended December 31, 2016 - no E&E assets were transferred to PP&E).

2017 Impairments

During 2017, the Company completed impairment reviews of its E&E assets. It was determined that the carrying amount of certain E&E assets primarily associated with VMM-11 in the Middle Magdalena basin were unlikely to be recovered by successful development or sale as the Company currently has plans to relinquish its interest in the block and has no further plans to continue exploration activities on the block. The impairment review compared the carrying value of the assets to the recoverable amount. The recoverable amount was estimated using fair value less costs of disposal (level 3 inputs) and was determined to be $nil for these assets. It was determined that the impairment was $35.6 million which is recorded in the consolidated statement of comprehensive income (loss) for the twelve months ended December 31, 2017.

2016 Impairments

During 2016, the Company completed impairment reviews of its E&E assets. It was determined that the carrying amount of certain E&E assets primarily associated with Cerrero Block, Cebucan Block and Block 24 in the Northern Llanos basin were unlikely to be recovered by successful development or sale as the Company had relinquished its interests in the three blocks during the fourth quarter of 2016. The impairment review compared the carrying value of the assets to the recoverable amount. The recoverable amount was estimated using fair value less costs of disposal (level 3 inputs) and was determined to be $nil for these assets. It was determined that the impairment was $69.9 million which is recorded in the consolidated statement of comprehensive income (loss) for the twelve months ended December 31, 2016.

At December 31, 2017 and December 31, 2016 the Company did not have E&E assets in Canada.

8. Property, Plant and Equipment

	Canada	Colombia	Total
Cost			
Balance at December 31, 2015	$ 3,607	$ 1,537,663	$ 1,541,270
Additions	126	59,393	59,519
Additions related to property acquisition	—	4,025	4,025
Changes in decommissioning and environmental liability	—	13,042	13,042
Balance, December 31, 2016	$ 3,733	$ 1,614,123	$ 1,617,856
Additions	47	135,536	135,583
Transfers from E&E assets	—	29,757	29,757
Additions related to property acquisition	—	9,994	9,994
Changes in decommissioning and environmental liability	—	(1,588)	(1,588)
Balance at December 31, 2017	**$ 3,780**	**$ 1,787,822**	**$ 1,791,602**
Accumulated Depreciation, Depletion and Amortization			
Balance at December 31, 2015	$ 3,062	$ 963,895	$ 966,957
Depletion and depreciation for the year	286	115,491	115,777
DD&A included in crude oil inventory costing	—	(745)	(745)
Impairment	—	9,597	9,597
Balance, December 31, 2016	$ 3,348	$ 1,088,238	$ 1,091,586
Depletion and depreciation for the year	185	98,553	98,738
DD&A included in crude oil inventory costing	—	(159)	(159)
Balance at December 31, 2017	**$ 3,533**	**$ 1,186,632**	**$ 1,190,165**
Net book value:			
As at December 31, 2015	$ 545	$ 573,768	$ 574,313
As at December 31, 2016	$ 385	$ 525,885	$ 526,270
As at December 31, 2017	**$ 247**	**$ 601,190**	**$ 601,437**

Additions and Transfers

During 2017, property, plant and equipment ("PPE") additions of $135.6 million mainly relate to drilling costs in Colombia at Block LLA-34, Cabrestero block, and the Aguas Blancas block. For the year ended December 31, 2017, $29.8 million of E&E assets were transferred to PP&E related to the Aguas Blancas block (year ended December 31, 2016 - no E&E assets were transferred to PP&E).

During the year ended December 31, 2016, additions mainly related to development expenditures in the amount of $59.5 million in Colombia at Block LLA-34 and exploration drilling on Block LLA-32 and Cabrestero. There were no transfers from E&E for the year ended December 31, 2016.

For the year ended December 31, 2017 future development costs of $397.3 million (year ended December 31, 2016 - $253.2 million) were included in the depletion calculation for development and production assets. For the year ended December 31, 2017 $4.2 million of general and administrative costs (year ended December 31, 2016 - $3.9 million) have been capitalized in respect of development and production activities during the current period.

Impairments

The carrying amounts of the Company's PP&E assets are reviewed at each reporting date to determine whether there is any indication of impairment. At December 31, 2017 there was no indication of impairment noted.

For the year ended December 31, 2016 as a result of the continued low oil price environment at the time an indication of impairment was identified for all CGUs during 2016 and impairment tests were performed. The Company determined that the carrying amount of the Block LLA-30 CGU assets exceeded its recoverable amount. An impairment of $9.6 million was recorded in the consolidated statement of comprehensive income (loss). The recoverable amount was determined using fair value less costs of disposal.

The fair value for the producing properties in this CGU was calculated based on discounted after-tax cash flows of proved and probable reserves using forecast prices and cost estimates, consistent with the Company's independent qualified reserves evaluators. This approach requires assumptions about revenue, future oil prices, tax rates and discount rates, all of which are level 3 inputs. Refer to note 11 – Goodwill for the future crude oil prices used by Parex' independent reserve evaluator. There were no E&E assets associated with this CGU. Future cash flows were discounted using an after tax rate of 11 percent. As at December 31, 2016, the recoverable amount of the CGU was estimated to be $7.6 million. The impairment was due to a negative technical revision that resulted in a reserve write-down. A 1% change to the assumed discount rate or forward price estimates over the life of the reserves would have an insignificant impact on the impairment.

9. Acquisitions

a) 2017 Llanos Basin additional working interest acquisition

On October 4, 2017, Parex through its subsidiaries acquired an additional 17.5% working interest in the Block LLA-32 and 50% working interest in Block LLA-40 in Colombia's Llanos Basin (the "Llanos 2017 Acquisition"). The Company paid total net consideration of $5.0 million. The Llanos 2017 Acquisition increased the Company's working interest in Block LLA-32 to 87.5% and Block LLA-40 to 100%.

The consolidated statement of comprehensive income (loss) includes results of operation of the Llanos 2017 Acquisition since the closing date of October 4, 2017. There were no transaction costs associated with the Llanos Acquisition.

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

Assets acquired and liabilities assumed		
PP&E	$	11,137
Decommissioning and environmental liabilities		(2,537)
	$	**8,600**
Consideration for the acquisition		
Cash paid	$	5,697
Settlement of pre-existing relationship		(705)
Total net consideration paid	**$**	**4,992**
Gain on acquisition	**$**	**3,608**

In addition to the $3.6 million gain on acquisition above, the Company recorded a $1.4 million gain on the remeasurement of the pre-existing 50% interest in Block LLA-40. Both gains have been recorded in the financial statement line item "Finance Income" in the Consolidated Statement of Comprehensive Income (Loss). Refer to Note 11.

The pro forma results for year ended December 31, 2017 are shown below, as if the Llanos 2017 Acquisition had occurred on January 1, 2017. Pro forma results are not indicative of actual results or future performance.

Oil sales	$	7,749
Net income	$	2,879
Basic net income per share	$	0.02
Diluted net income per share	$	0.02

The consolidated statement of comprehensive income (loss) for the year ended December 31, 2017 includes $2.1 million of oil sales attributable to the assets acquired since the Llanos 2017 Acquisition. Revenue less direct costs for the period ended December 31, 2017 attributable to the assets acquired since the Llanos 2017 Acquisition is $0.9 million.

b) 2016 Llanos Basin additional working interest acquisition

On September 12, 2016, Parex acquired an additional 50% working interest in the El Eden Block and the Los Ocarros Block in Colombia's Llanos Basin (the "Llanos 2016 Acquisition"). The Company paid total net consideration of $4.0 million. The Llanos 2016 Acquisition increased the Company's working interest in both of the blocks to 100%.

The consolidated statement of comprehensive income (loss) includes results of operation of the Llanos 2016 Acquisition since the closing date of September 12, 2016. There were no transaction costs associated with the Llanos Acquisition.

This transaction has been accounted for using the acquisition method whereby the assets acquired and the liabilities assumed are recorded at fair values. As the fair value of the identifiable assets was determined to equal the purchase price, no goodwill arose on the transaction. The following table summarizes the recognizable assets acquired and consideration paid pursuant to the acquisition:

Assets acquired and liabilities assumed		
PP&E	$	6,561
Decommissioning and environmental liabilities		(2,536)
	$	**4,025**

Consideration for the acquisition		
Cash paid	$	4,025
Total net consideration paid	**$**	**4,025**

The pro forma results for the year ended December 31, 2016 are shown below, as if the Llanos 2016 Acquisition had occurred on January 1, 2016. Pro forma results are not indicative of actual results or future performance.

Oil sales	$	9,539
Net income	$	810
Basic net income per share	$	0.01
Diluted net income per share	$	0.01

The consolidated statement of comprehensive income (loss) for the year ended December 31, 2016 includes $3.7 million of oil sales attributable to the assets acquired since the Llanos 2016 Acquisition. Revenue less direct costs for the period ended December 31, 2016 attributable to the assets acquired since the Llanos 2016 Acquisition is $0.8 million.

10. Goodwill

		December 31, 2017		December 31, 2016
Goodwill	**$**	**73,452**	$	73,452

Impairment test of goodwill

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

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

Valuation Techniques

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

Significant Assumptions

Oil Reserves

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

Future Oil Prices

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

Prices used at December 31, 2017 are as follows:

	2018	**2019**	**2020**	**2021**	**2022**	**Thereafter**
Brent ($US/bbl)	65.50	63.50	63.00	66.00	69.00	2% increase per year

Prices used at December 31, 2016 are as follows:

	2017	**2018**	**2019**	**2020**	**2021**	**Thereafter**
Brent ($US/bbl)	57.00	61.00	66.00	70.00	74.00	2% increase per year

Discount Rate

The Company assumed a discount rate in order to calculate the present value of its projected cash flows. The discount rate represented a weighted average cost of capital ("WACC") for comparable companies operating in similar industries, based on publicly available information. The WACC is an estimate of the overall required rate of return on an investment for both debt and equity owners and serves as the basis for developing an appropriate discount rate. Its determination requires separate analysis of the cost of equity and debt, and considers a risk premium based on an assessment of risks related to the projected cash flows of the group of Colombia based CGUs whose revenues are denominated in USD. The after tax discount rate used in performing the impairment test was 11 percent (year ended December 31, 2016 - 11 percent).

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

11. Net Finance (Income) Expense

For the year ended December 31,		**2017**		2016
Bank charges and credit facility fees	**$**	**2,742**	$	2,614
Accretion on decommissioning and environmental liabilities		**3,965**		1,831
Colombian net wealth tax		**894**		2,228
Interest and other income		**(2,369)**		(1,260)
Gain on property acquisition		**(5,002)**		—
Bad debt expense		**1,463**		—
Loss on disposition of tangible assets		**605**		—
Loss on overlifted oil volumes		**—**		3,610
Net finance expense	**$**	**2,298**	$	9,023

For the year ended December 31,		**2017**		2016
Non-cash finance (income) expense	**$**	**(432)**	$	5,441
Cash finance expense		**2,730**		3,582
Net finance expense	**$**	**2,298**	$	9,023

12. Other Long-Term Liabilities

Other long-term liabilities are comprised of the following:

		December 31, 2017		December 31, 2016
Long-term SARs payable	**$**	**1,250**	$	1,652
Long-term DSUs payable		**2,474**		—
Long-term CRSUs payable		**994**		—
	$	**4,718**	$	1,652

13. Decommissioning and Environmental Liabilities

		Decommissioning		Environmental		Total
Balance, December 31, 2015	$	26,811	$	8,588	$	35,399
Additions		5,241		703		5,944
Settlements of obligations during the year		(75)		(103)		(178)
Accretion expense		1,432		399		1,831
Additions related to change in estimate - inflation and discount rates		7,697		1,482		9,179
Additions related to change in estimate - costs		(2,386)		1,677		(709)
Foreign exchange (gain)		—		(320)		(320)
Balance, December 31, 2016	$	38,720	$	12,426	$	51,146
Additions		5,313		2,223		7,536
Settlements of obligations during the year		(954)		(437)		(1,391)
Accretion expense		2,549		1,416		3,965
Additions related to change in estimate - inflation and discount rates		(9,773)		(1,809)		(11,582)
Additions related to change in estimate - costs		391		2,499		2,890
Foreign exchange (gain) loss		528		(412)		116
Balance, December 31, 2017		**36,774**		**15,906**		**52,680**
Current obligation		(4,159)		(5,609)		(9,768)
Long-term obligation	**$**	**32,615**	**$**	**10,297**	**$**	**42,912**

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

The total decommissioning and environmental liability is estimated based on the Company's net ownership in wells drilled as at December 31, 2017, the estimated costs to abandon and reclaim the wells and well sites and the estimated timing of the costs to be paid in future periods. The total undiscounted amount of cash flows required to settle the Company's decommissioning liability is approximately $66.4 million as at December 31, 2017 (December 31, 2016 – $92.1 million) with the majority of these costs anticipated to occur in 2021 or later. A risk-free discount rate of 7.5 percent and an inflation rate of 4.0 percent were used in the valuation of the liabilities (December 31, 2016 – 7.2 percent risk-free discount rate and a 7.5 percent inflation rate). The risk-free discount rate and the inflation rate used in 2017 are based on forecast Colombia rates.

Included in the decommissioning liability is $4.2 million (December 31, 2016 – $4.2 million) that is classified as a current obligation.

The total undiscounted amount of cash flows required to settle the Company's environmental liability is approximately $19.0 million as at December 31, 2017 (December 31, 2016 – $16.1 million) with the majority of these costs anticipated to occur in 2018 or later in Colombia. A risk-free discount rate of 7.5 percent and an inflation rate of 4.0 percent were used in the valuation of the liabilities (December 31, 2016 – 7.2 percent risk-free discount rate and a 7.5 percent inflation rate). The risk-free discount rate and the inflation rate used in 2017 are based on forecast Colombia rates.

Included in the environmental liability is $5.6 million (December 31, 2016 –$6.7 million) that is classified as a current obligation.

14. Share Capital

a) Issued and outstanding common shares

	Number of shares		Amount
Balance, December 31, 2015	151,489,302	$	812,737
Issued for cash – exercise of options and RSUs	1,501,193		5,492
Allocation of contributed surplus – exercise of options and RSUs	—		3,998
Balance, December 31, 2016	152,990,495	$	822,227
Issued for cash – exercise of options and RSUs	2,328,239		9,906
Allocation of contributed surplus – exercise of options and RSUs	—		6,762
Repurchase of shares	(576,600)		(2,729)
Balance at December 31, 2017	**154,742,134**	**$**	**836,166**

The Company has authorized an unlimited number of voting common shares without nominal or par value.

In 2017, a total of 2,328,239 options and RSUs were exercised for proceeds of $9.9 million (year ended December 31, 2016 - 1,501,193 options and RSUs were exercised for $5.5 million).

In 2017, the Company repurchased 576,600 (year ended December 31, 2016 - nil) common shares pursuant to its Normal Course Issuer Bid at a cost of $7.5 million (average cost per share of Cdn$16.39). The cost to repurchase common shares at a price in excess of their average book value has been charged to retained earnings.

b) Stock options

The Company has a stock option plan which provides for the issuance of options to the Company's officers and certain employees to acquire common shares. The maximum number of options and restricted share units (including performance share units) reserved for issuance under the stock option and restricted share unit plans may not exceed 10 percent of the number of common shares issued and outstanding. The stock options vest over a three-year period and expire five years from the date of grant.

	Number of options	Weighted average exercise price Cdn$/option
Balance, December 31, 2015	7,854,511	8.11
Granted	1,375,500	15.60
Exercised	(1,179,235)	6.07
Forfeited	(309,002)	9.80
Balance, December 31, 2016	7,741,774	9.68
Granted	666,500	15.88
Exercised	(1,884,422)	6.84
Forfeited	(44,417)	12.82
Balance, December 31, 2017	**6,479,435**	**11.13**

Stock options outstanding and the weighted average remaining life of the stock options at December 31, 2017 are as follows:

	Options outstanding			Options vested		
Exercise price Cdn$	Number of options	Weighted average remaining life (years)	Weighted average exercise price Cdn$/ option	Number of options	Weighted average remaining life (years)	Weighted average exercise price Cdn$/option
$4.36 - $6.31	1,477,618	0.79	6.06	1,477,618	0.79	6.06
$6.32 - $10.59	1,296,506	1.86	10.15	1,271,506	1.86	10.22
$10.60 - $11.24	1,696,935	2.86	10.94	1,092,423	2.86	10.94
$11.25 - $15.84	1,415,276	3.82	15.47	457,947	3.66	15.37
$15.85- $16.87	593,100	4.17	16.05	6,250	3.78	16.87
	6,479,435	2.52	11.13	4,305,744	1.94	9.53

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions:

For the year ended December 31,	**2017**	2016
Risk-free interest rate (%)	**1.10**	0.76
Expected life (years)	**4**	4
Expected volatility (%)	**44**	47
Forfeiture rate (%)	**3**	3
Expected dividends	—	—

The weighted average fair value at the grant date for the year ended December 31, 2017 was Cdn$5.62 per option (year ended December 31, 2016 – Cdn$5.76 per option). The weighted average share price on the exercise date for options exercised in 2017 was Cdn$16.87 (year ended December 31, 2016 – Cdn$14.28).

c) *Restricted and performance share units*

The Company has in place a restricted share unit plan pursuant to which the Company may grant restricted shares to certain employees. The restricted shares vest at 33 percent on each of the first, second and third anniversaries of the grant date and expire five years from date of grant.

	Number of RSU's	Weighted average exercise price Cdn$/RSU
Balance, December 31, 2015	2,306,965	0.01
Granted	692,475	0.01
Exercised	(321,958)	0.01
Forfeited	(89,336)	0.01
Balance, December 31, 2016	2,588,146	0.01
Granted	632,550	0.01
Exercised	(443,817)	0.01
Forfeited	(46,584)	0.01
Balance, December 31, 2017	**2,730,295**	**0.01**

RSUs outstanding and the weighted average remaining life of the RSUs at December 31, 2017 are as follows:

	RSUs outstanding		RSUs vested	
Exercise price Cdn$	Number of RSUs	Weighted average remaining life (years)	Number of RSUs	Weighted average remaining life (years)
0.01	**2,730,295**	**3.11**	**1,343,482**	**2.41**

The fair value of each RSU granted is based on the market price of Parex shares on the date of issuance. The weighted average fair value at the grant date for the year ended December 31, 2017 was Cdn$15.99 per RSU (year ended December 31, 2016 – Cdn$11.53 per RSU). For the year ended December 31, 2017 a weighted average forfeiture rate of 3% was applied (year ended December 31, 2016 – 3%).

Pursuant to the restricted share unit plan, the Company may grant performance share units to certain employees. The performance share units vest three years after the grant date and expire one month after the vesting date. The vesting of PSUs is conditional on the satisfaction of certain performance criteria as determined by the Company's Board of Directors. If the Company satisfies the performance criteria, PSUs become eligible to vest and a pre-determined multiplier is applied to eligible PSUs.

	Number of PSU's	Weighted average exercise price Cdn$/PSU
Balance at December 31, 2016	—	—
Granted	103,500	0.01
Balance, December 31, 2017	103,500	0.01

The fair value of each PSU granted is based on the share price at which the common shares of the Company traded for on the grant date. The weighted average fair value at the grant date for the year ended December 31, 2017 was Cdn$16.01 per PSU.

d) Share-based compensation expense

For the year ended December 31,		2017		2016
Option expense	$	6,917	$	5,497
Restricted share units expense		11,464		6,544
Deferred share units expense		—		777
Total	$	18,381	$	12,818

Due to an amendment to the DSU plan in the current year, the prior period DSU expense has been reclassified to cash settled share-based compensation expense. Refer to note 15.

15. Cash Settled Incentive Plans

a) Share appreciation rights ("SARs")

Parex Colombia has a SARs plan that provides for the issuance of SARs to certain employees of Parex Colombia. The plan entitles the holders to receive a cash payment equal to the excess of the market price of the Company's common shares at the time of exercise over the grant price. At any time, if the current market price of the Company's common shares exceeds four times the grant price, Parex has the option to require the holders to exercise all vested SARs. SARs typically vest over a three-year period and expire five years from the date of grant. The SARs liability cannot be settled by the issuance of common shares.

	Number of SARs	Weighted average exercise price Cdn$/SAR
Balance, December 31, 2015	3,475,001	9.03
Granted	1,574,468	15.55
Exercised	(961,233)	7.72
Forfeited	(281,999)	10.26
Balance, December 31, 2016	3,806,237	11.91
Granted	134,086	16.39
Exercised	(1,323,125)	9.67
Forfeited	(229,191)	12.20
Balance,December 31, 2017	**2,388,007**	**13.38**

As at December 31, 2017 873,208 SARs were vested (December 31, 2016 – 1,077,450).

Obligations for payments of cash under the SARs plan are accrued as compensation expense over the vesting period based on the fair value of SARs, subject to appreciation limits specified in the plan. The fair value of SARs is measured using the Black-Scholes pricing model at each reporting date based on weighted average pricing assumptions noted below:

For the year ended December 31,	2017	2016
Risk-free interest rate (%)	1.79	0.88
Expected life (years)	4	4
Expected volatility (%)	43	46
Share price ($/Cdn)	18.16	16.90
Expected dividends	—	—

As at December 31, 2017, the total SARs liability accrued is $11.6 million (December 31, 2016 - $13.5 million) of which $1.2 million (December 31, 2016 - $1.7 million) is classified as long-term in accordance with the three year vesting period. For the year ended December 31, 2017, Parex recorded $4.7 million of compensation costs related to the outstanding SARs (year ended December 31, 2016 – $12.9 million).

b) Deferred share units

The Company has in place a deferred share unit plan pursuant to which the Company may grant deferred shares to all non-employee directors. The deferred share units vest immediately and are settled in cash upon the retirement of the non-employee director from the Parex Board. The value of the DSUs at the exercise date is equivalent to the five day weighted average share price at which the common shares of the Company traded for immediately preceding the exercise date. DSUs can only be redeemed following retirement from the Board of Directors of the Company in accordance with the terms of the DSU Plan. The DSUs liability cannot be settled by the issuance of common shares.

	Number of DSU's	Weighted average exercise price Cdn$/DSU
Balance, December 31, 2015	78,600	—
Granted	67,300	—
Balance at December 31, 2016	145,900	—
Granted	65,075	—
Exercised on board retirement	(17,000)	—
Balance, December 31, 2017	**193,975**	—

The fair value at the grant date is equivalent to the five day weighted average share price at which the common shares of the Company traded for immediately preceding the grant date. The weighted average fair value at the grant date for the year ended December 31, 2017 was Cdn $16.67 per DSU (year ended December 31, 2016 - Cdn$16.82 per DSU).

Given the DSUs vest immediately, obligations for payments of cash under the DSUs plan are accrued as compensation expense immediately based on the fair value of the DSU. As at December 31, 2017 the total DSUs liability accrued is $2.8 million (December 31, 2016 -$nil) of which $2.5 million (December 31, 2016 - $nil) is classified as long-term in accordance with the terms of the DSU plan.

c) Cash settled restricted share units ("CRSUs")

Parex Colombia has a CRSUs plan that provides for the issuance of CRSUs to certain employees of Parex Colombia. The plan entitles the holders to receive a cash payment equal to the market price of the Company's common shares at the time of exercise. CRSUs vest over a three-year period and are exercised at the vest date. The CRSUs liability cannot be settled by the issuance of common shares.

	Number of CRSUs	Weighted average exercise price Cdn$/CRSU
Balance, December 31, 2016	—	—
Granted	**504,020**	—
Forfeited	**(11,670)**	—
Balance, December 31, 2017	**492,350**	**—**

As at December 31, 2017, no CRSUs were fully vested.

Obligations for payments of cash under the CRSUs plan are accrued as compensation expense over the vesting period based on the fair value of CRSUs. The fair value of CRSUs is equivalent to the trading value of a common share of the Company on the valuation date. As at December 31, 2017, the total CRSUs liability accrued is $2.2 million (December 31, 2016 -$nil) of which $1.0 million (December 31, 2016 - $nil) is classified as long-term in accordance with the three year vesting period. For the twelve months ended December 31, 2017, Parex recorded $2.2 million of compensation costs related to the outstanding CRSUs (year ended December 31, 2016 – $nil).

d) Cash settled share-based compensation

For the year ended December 31,		**2017**		2016
SARs expense	**$**	**4,662**	$	12,927
CRSUs expense		**2,187**		—
DSUs expense		**1,630**		—
Total	**$**	**8,479**	$	12,927

16. Income Tax

The components of tax expense for 2017 and 2016 were as follows:

For the year ended December 31,		2017		2016
Current tax expense	**$**	**43,910**	$	9,892
Adjustments in respect of prior period		**110**		(4,264)
Total current tax expense	**$**	**44,020**	$	5,628
Deferred tax (recovery)		**(28,806)**		(30,299)
Total tax expense (recovery)	**$**	**15,214**	$	(24,671)

Factors affecting tax expense for the year

The standard Colombian corporate income tax rate for 2017 was 40 percent (year ended December 31, 2016 – 40 percent). The following is a reconciliation of income taxes calculated at the Colombian corporate tax rate to the tax expense for 2017 and 2016:

For the year ended December 31,		2017		2016
Income (loss) before tax	**$**	**170,292**	$	(71,115)
Income before tax multiplied by the standard rate of Colombian corporate tax of 40% (2016 – 40%)		**68,117**		(28,446)
Effects of:				
Income taxes recorded at rates different from the Colombian tax rate		**10,762**		(746)
Impact of Colombian tax rate changes		**(531)**		(7,424)
Income/expenses taxable/deductible at different rates		**(29,930)**		—
Non deductible expense and other permanent differences		**881**		13,058
Share-based compensation		**5,403**		3,461
Adjustment in respect of prior period		**(1,519)**		(7,765)
Non-taxable dividends		**(7,249)**		—
Foreign exchange impact on tax pools denominated in foreign currency		**(9,776)**		3,102
Change in unrecognized deferred tax assets		**(20,944)**		89
Total tax expense (recovery)	**$**	**15,214**	$	(24,671)

The Colombian government enacted legislation in December 2016 containing tax rate changes effective January 1, 2017. Colombian current tax rates are as follows: 40% for 2017; 37% in 2018; and 33% thereafter.

The analysis of deferred income tax assets as follows:

		December 31, 2017		December 31, 2016
Deferred tax assets to be settled within 12 months	**$**	**6,907**	$	8,327
Deferred tax assets to be settled after more than 12 months		**13,908**		8,997
Deferred income tax assets	**$**	**20,815**	$	17,324

The analysis of deferred income tax liabilities as follows:

		December 31, 2017		December 31, 2016
Deferred tax liabilities to be settled within 12 months	**$**	**425**	$	190
Deferred tax liabilities to be settled after more than 12 months		**29,920**		55,470
Deferred income tax liability	**$**	**30,345**	$	55,660
Net deferred tax liability (asset)	**$**	**9,530**	$	38,336

The deferred income tax liabilities and assets to be settled (recovered) within 12 months represents management's estimate of the timing of the reversal of temporary differences and does not correlate to the current income tax expense of the subsequent year.

The movement during the year in the deferred income tax (liabilities) assets and the net components is as follows:

Deferred Tax (Liability)		**December 31, 2017**		Charged (credited) to the statement of comprehensive income /(loss)		December 31, 2016		Charged (credited) to the statement of comprehensive income /(loss)
PP&E	**$**	**(55,500)**	$	1,458	$	(56,958)	$	55,368
Loss carry forwards		**—**		—		—		(27,616)
Decommissioning liability		**18,024**		16,345		1,679		(10,554)
SARs		**4,553**		4,553		—		(1,986)
Other		**2,578**		2,959		(381)		(2,237)
Balance, end of period	**$**	**(30,345)**	$	25,315	$	(55,660)	$	12,975

The movement during the year in the deferred income tax assets and the net components is as follows:

Deferred Tax Asset		**December 31, 2017**		Charged (credited) to the statement of comprehensive income /(loss)		December 31, 2016		Charged (credited) to the statement of comprehensive income /(loss)
PP&E	**$**	**(587)**	$	24,473	$	(25,060)	$	(25,060)
Loss carry forwards		**20,652**		4,605		16,047		16,047
Decommissioning liability		**54**		(15,939)		15,993		15,993
SARs		**—**		(4,445)		4,445		4,445
Other		**696**		(5,203)		5,899		5,899
Balance, end of period	**$**	**20,815**	$	3,491	$	17,324	$	17,324

The Company has losses as well as other cumulative tax deductions in excess of book value in Canada available to reduce future taxable income in future years. During the year ended December 31, 2017 the Company recognized the benefit of $21.0 million of previously unrecognized deferred tax assets in Canada as it is now probable that the Company will realize the benefit. At December 31, 2017 the deferred tax asset amount recorded in Canada is $19.3 million. The Company did not recognize deferred income tax asset on capital losses and other items in Canada of $234.0 million. Non-capital losses in Canada expire in 20 years and capital losses carry-forward indefinitely. The Company does not have losses available in Colombia. Amounts denominated in foreign currency have been translated at the December 31, 2017 exchange rate. At December 31, 2017 the Company had the following losses carry-forward:

		Canada
Year of expiry		
2030	$	5,377
2031		21,153
2032		24,145
2033		5,310
2034		2,365
2035		9,344
2036		808
Indefinitely		167,115
	$	**235,617**

Earnings retained by subsidiaries amounted to $101.3 million at December 31, 2017 (December 31, 2016 - $21.4 million). No provision has been made for withholding and other taxes that would become payable on the distribution of these earnings as it is not expected that they will be remitted in the foreseeable future.

17. Net income (loss) per Share

a) Basic net income (loss) per share

For the year ended December 31,	2017	2016
Net income (loss)		
Net income (loss) for the purpose of basic net income (loss) per share	**$ 155,078**	$ (46,444)
Weighted average number of shares for the purposes of basic net (loss) per share (000's)	**154,209**	152,184
Basic net income (loss) per share	**$ 1.01**	$ (0.31)

b) Diluted net income (loss) per share

For the year ended December 31,	2017	2016
Net income (loss)		
Net income (loss) used to calculate diluted net income (loss) per share	**$ 155,078**	$ (46,444)
Weighted average number of shares for the purposes of basic net income (loss) per share (000's)	**154,209**	152,184
Dilutive effect of share options and RSUs on potential common shares	**3,063**	—
Weighted average number of shares for the purposes of diluted net income (loss) per share	**157,272**	152,184
Diluted net income (loss) per share	**$ 0.99**	$ (0.31)

For the twelve months ended December 31, 2017, 593,100 stock options were excluded from the diluted weighted average shares calculation as they were anti-dilutive. The Company reported a net loss for the twelve months ended December 31, 2016 and therefore all stock options and RSUs that were otherwise dilutive were anti-dilutive and excluded from the diluted earnings per share.

18. Supplemental Disclosure of Cash Flow Information

a) Net change in non-cash working capital

For the year ended December 31,	2017	2016
Accounts receivable	**$ (33,133)**	$ 33,836
Prepaids and other current assets	**674**	5,894
Crude oil inventory	**(204)**	373
Accounts payable and accrued liabilities	**49,475**	(23,472)
Depletion related to crude oil inventory	**(159)**	(745)
Net change in non-cash working capital	**$ 16,653**	$ 15,886
Operating	**$ 5,501**	$ 9,898
Investing	**11,152**	5,988
Financing	**—**	—
Net change in non-cash working capital	**$ 16,653**	$ 15,886

b) Interest and taxes paid

For the year ended December 31,	2017	2016
Cash interest paid	**$ 1,179**	$ 580
Cash income and equity taxes paid	**$ 2,627**	$ 20,728

19. Employee Salaries and Benefit Expenses

For the year ended December 31,		2017		2016
Salaries, bonuses and other short term benefits	$	30,093	$	26,804
Equity settled share-based compensation		18,381		12,818
Cash settled share-based compensation		8,479		12,927
	$	56,953	$	52,549

Employee salaries, bonuses and short-term benefits are included in general and administrative expenses in the consolidated statement of comprehensive income (loss). Stock option, SARs, RSUs, PSUs and DSUs expense are included in share-based compensation expense in the consolidated statement of comprehensive income (loss).

20. Capital Management

The Company's strategy is to maintain a strong capital base in order to provide flexibility in the future development of the business and maintain the confidence of investors and capital markets.

The Company manages its capital to achieve the following:

- Maintain balance sheet strength in order to meet the Company's strategic growth objectives; and
- Ensure financial capacity is available to fund the Company's exploration commitments.

Parex has a senior secured credit facility which as at December 31, 2017 had a borrowing base in the amount of $100.0 million (December 31, 2016 - $175.0 million). The credit facility was voluntarily reduced from $175.0 million to $100.0 million in May 2017 to reduce costs associated with the credit facility. The credit facility is intended to serve as means to increase liquidity and fund cash needs as they arise. As at December 31, 2017, $nil (December 31, 2016 - $nil) was drawn on the credit facility.

The Company has also provided a general security agreement to Export Development Canada ("EDC") in connection with the performance security guarantees that support letters of credit provided to the Colombian National Hydrocarbon Agency ("ANH") and Empresa Colombiana de Petroleos S.A. ("Ecopetrol") related to the exploration work commitments on its Colombian concessions (see note 23 - Commitments). This performance guarantee facility has a limit of $250.0 million (December 31, 2016 - limit of $200.0 million) of which $116.1 million (December 31, 2016 - $126.4 million) is utilized at December 31, 2017. At December 31, 2017, there is an additional $26.4 million (December 31, 2016 - $21.3 million) of letters of credit that are provided by a Latin American bank on an unsecured basis.

As at December 31, 2017 the Company's net working capital surplus was $163.4 million (December 31, 2016 - $93.3 million), of which $235.0 million is cash.

In the fourth quarter of 2017 the Company put in place an automatic share purchase plan with a broker in order to facilitate repurchases of up to 3.0 million of its common shares. Under the Company's automatic share purchase plan, the Company's broker may repurchase shares under the normal course issuer bid during the Company's self-imposed blackout periods. The repurchase plan is seen by management as a way to support shareholders through reduced dilution of common shares on share issuances related to stock-based compensation plans, and provides additional liquidity to common shares.

Parex has the ability to adjust its capital structure by issuing new equity or debt and making adjustments to its capital expenditure program to the extent the capital expenditures are not committed. The Company considers its capital structure at this time to include shareholders' equity and the credit facility. As at December 31, 2017 shareholders' equity was $888.3 million (December 31, 2016 - $713.8 million).

21. Financial Instruments and Risk Management

The Company's non-derivative financial instruments recognized on the consolidated balance sheet consist of cash, accounts receivable, accounts payable and accrued liabilities. Non-derivative financial instruments are recognized initially at fair value. The fair values of the current financial instruments approximate their carrying value due to their short-term maturity. The fair value of the revolving credit facility is equal to its carrying amount as the facility bears interest at floating rates and the credit spreads within the facility are indicative of market rates.

Long-term financial instruments of the Company carried on the consolidated balance sheet are carried at amortized cost with the exception of financial derivative instruments, specifically fixed price contracts, which are carried at fair value. There are no significant differences between the carrying amount of derivative financial instruments and their estimated fair values as at December 31, 2017.

The fair value of the Company's financial derivative instruments are quoted in active markets. The Company classifies the fair value of these transactions according to the following hierarchy.

Level 1 – quoted prices in active markets for identical financial instruments.
Level 2 – quoted prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; and model-derived valuations in which all significant inputs and significant value drivers are observable in active markets.
Level 3 – valuations derived from valuation techniques in which one or more significant inputs or significant value drivers are unobservable.

The Company's financial derivative instruments have been classified as level 2 based on the fair value hierarchy described above. The Company used the following techniques to determine the fair value measurements: Crude oil contracts are recorded at their estimated fair value based on the difference between the contracted price and the period end forward price for the same commodity, using quoted market prices or the period end forward price for the same commodity extrapolated to the end of the contract term.

a) Credit risk

Credit risk is the risk of loss associated with the inability of a third party to fulfill its payment obligations. The Company is exposed to the risk that third parties that owe it money do not meet their obligations. The Company assesses the financial strength of its joint venture partners and oil marketing counterparties in its management of credit exposure.

The Company for the year ended December 31, 2017 had the majority of its oil sales to 10 counterparties. Accounts receivable balance as at December 31, 2017 are substantially made up of receivables with customers in the oil and gas industry and are subject to normal industry credit risks. The Company historically has not experienced any collection issues with its crude oil customers. At December 31, 2017 there are no accounts receivable past due (December 31, 2016 - $0.6 million).

As at December 31, 2017 and 2016 the Company's accounts receivable are aged as follows:

For the year ended December 31,		**2017**		2016
Current (less than 90 days)	**$**	**79,152**	$	45,405
Past due (more than 90 days)		**—**		614
Total	**$**	**79,152**	$	46,019

None of the Company's receivables are impaired at December 31, 2017. The maximum credit risk exposure associated with accounts receivable is the total carrying value.

b) Liquidity risk

The Company's approach to managing liquidity risk is to have sufficient cash and/or credit facilities to meet its obligations when due. Management typically forecasts cash flows for a period of 12 to 36 months to identify any financing requirements. Liquidity is managed through daily and longer-term cash, debt and equity management strategies. These include estimating future cash generated from operations based on reasonable production and pricing assumptions, estimating future discretionary and non-discretionary capital expenditures and assessing the amount of equity or debt financing available. The Company is committed to maintaining a strong balance sheet and has the ability to change its capital program based on expected operating cash flows. The balance drawn on the Company's $100.0 million credit facility at December 31, 2017 was $nil.

The following are the contractual maturities of financial liabilities at December 31, 2017:

		Less than 1 year	**2-3 Years**	**4-5 Years**	**Thereafter**		**Total**
Accounts payable and accrued liabilities [(1)]	$	91,736	—	—	—	$	91,736
Cash settled equity plans payable		11,889	4,718	—	—		16,607
Total	$	103,625	4,718	—	—	$	108,343

(1) Includes the liability for derivative financial instruments.

The following are the contractual maturities of financial liabilities at December 31, 2016:

		Less than 1 year	**2-3 Years**	**4-5 Years**	**Thereafter**		**Total**
Accounts payable and accrued liabilities	$	76,199	—	—	—	$	76,199
SARs payable		11,818	1,652	—	—		13,470
Total	$	88,017	1,652	—	—	$	89,669

c) *Commodity price risk*

The Company is exposed to commodity price movements as part of its operations, particularly in relation to the prices received for its oil production. Crude oil is sensitive to numerous worldwide factors, many of which are beyond the Company's control. Changes in global supply and demand fundamentals in the crude oil market and geopolitical events can significantly affect crude oil prices. Consequently, these changes could also affect the value of the Company's properties, the level of spending for exploration and development and the ability to meet obligations as they come due. The Company's oil production is sold under short-term contracts, exposing it to the risk of near-term price movements.

As at December 31, 2017 the Company had outstanding risk management contracts which are used to manage its exposure to downward fluctuations in the price of crude oil.

The following is a summary of the ICE Brent priced crude oil risk management contracts in place for the year ended December 31, 2017:

Period Hedged	Reference	Volume bbls/d	Sold Put	Purchased Put	Sold Call	Premium
January 1, 2017 to February 28, 2017	ICE Brent	5,000	$ 44.00	$ 48.00	$ 63.35	$ —
January 1, 2017 to March 31, 2017	ICE Brent	5,000	$ 40.00	$ 45.00	$ 59.40	$ —
April 1, 2017 to June 30, 2017	ICE Brent	5,000	$ 40.00	$ 45.00	$ 64.00	$ —
April 1, 2017 to September 30, 2017	ICE Brent	5,000	$ 40.00	$ 50.00	$ —	$ 1.30
July 1, 2017 to September 30, 2017	ICE Brent	5,000	$ 45.00	$ 50.00	$ —	$ 0.95
October 1, 2017 to December 31, 2017	ICE Brent	5,000	$ 40.00	$ 45.00	$ 61.75	$ —
January 1, 2018 to March 31, 2018	ICE Brent	5,000	$ 47.00	$ 50.00	$ —	$ 0.40
January 1, 2018 to March 31, 2018	ICE Brent	5,000	$ 47.00	$ 50.00	$ —	$ 0.25
January 1, 2018 to June 30, 2018	ICE Brent	5,000	$ 47.00	$ 50.00	$ —	$ 0.27

The fair value of the ICE Brent priced crude oil risk management contracts of $0.1 million payable (December 31, 2016 – payable of $1.7 million) is recorded in the financial statement line item "Derivative financial instruments" in the consolidated balance sheet.

The table below summarizes (gain) loss on the commodity risk management contracts that were in place during the year ended December 31, 2017 and 2016:

For the year ended December 31,	**2017**	2016
Realized loss (gain) on commodity risk management contracts	**$ 513**	$ (948)
Premiums paid on commodity risk management contracts	**1,875**	7,755
Unrealized loss (gain) on commodity risk management contracts	**(1,178)**	3,859
Total	**$ 1,210**	$ 10,666

There are no unamortized premiums at December 31, 2017 or 2016.

As shown in the table above, as at December 31, 2017, Parex had committed to the future sale of 1,805,000 barrels of oil with collars from Brent oil prices of $47.00 to $50.00 per bbl. The following sensitivity shows the resulting unrealized loss (gain) and impact on income (loss) before tax for the oil hedged contracts if Brent oil price were to increase/decrease by $10/bbl from the spot rate as at December 31, 2017:

	Brent Price	**Impact for the year ended December 31, 2017**	
		Increase of $10/bbl	Decrease of $10/bbl
Oil hedged contract loss (gain)	Period end	**$ 44**	**$ (310)**

Subsequent to December 31, 2017, Parex entered into the following ICE Brent priced crude oil risk management contracts:

Period Hedged	Reference	Volume bbls/d	Sold Put	Purchased Put	Sold Call	Premium
April 1, 2018 to September 30, 2018	ICE Brent	10,000	$ 50.00	$ 55.00	$ —	$0.40

22. Segmented Information

The Company has foreign subsidiaries and the following segmented information is provided:

For the year ended December 31, 2017	Canada	Colombia	Total
Oil and natural gas sales	$ —	$ 659,407	$ 659,407
Royalties	—	(58,540)	(58,540)
Revenue	—	600,867	600,867
Commodity risk management contracts	—	(1,210)	(1,210)
	—	599,657	599,657
Expenses			
Production	—	69,169	69,169
Transportation	—	141,475	141,475
Purchased oil	—	5,653	5,653
General and administrative	11,708	22,381	34,089
Legal Settlement	15,000	—	15,000
Equity settled share-based compensation expense (recovery)	20,011	(1,630)	18,381
Cash settled share-based compensation expense	—	8,479	8,479
Depletion, depreciation and amortization	185	98,553	98,738
Foreign exchange (gain) loss	24	438	462
Impairment of exploration and evaluation assets	—	35,621	35,621
	46,928	380,139	427,067
Finance (income)	(699)	(6,672)	(7,371)
Finance expense	1,105	8,564	9,669
Net finance expense	406	1,892	2,298
Net income (loss) before taxes	(47,334)	217,626	170,292
Current tax expense	—	44,020	44,020
Deferred tax (recovery)	—	(28,806)	(28,806)
Net income (loss)	$ (47,334)	$ 202,412	$ 155,078
Capital assets (end of year)	$ 247	$ 708,334	$ 708,581
Capital expenditures	$ 47	$ 212,299	$ 212,346
Total assets (end of year)	$ 71,280	$ 1,050,628	$ 1,121,908

For the year ended December 31, 2016	Canada	Colombia	Total
Oil and natural gas sales	$ —	$ 445,488	$ 445,488
Royalties	—	(34,327)	(34,327)
Revenue	—	411,161	411,161
Commodity risk management contracts	—	(10,666)	(10,666)
	—	400,495	400,495
Expenses			
Production	—	53,250	53,250
Transportation	—	130,930	130,930
Purchased oil	—	25,109	25,109
General and administrative	13,920	16,894	30,814
Share-based compensation	12,818	—	12,818
Share appreciation rights	—	12,927	12,927
Depletion, depreciation and amortization	287	115,490	115,777
Foreign exchange loss	47	1,438	1,485
Impairment of property, plant and equipment	—	9,597	9,597
Impairment of exploration and evaluation assets	—	69,880	69,880
	27,072	435,515	462,587
Finance (income)	(566)	(694)	(1,260)
Finance expense	1,506	8,777	10,283
Net finance expense	940	8,083	9,023
Net (loss) before taxes	(28,012)	(43,103)	(71,115)
Current tax expense	—	5,628	5,628
Deferred tax (recovery)	—	(30,299)	(30,299)
Net (loss)	$ (28,012)	$ (18,432)	$ (46,444)
Capital assets (end of year)	$ 355	$ 626,939	$ 627,294
Capital expenditures	$ 126	$ 111,596	$ 111,722
Total assets (end of year)	$ 83,861	$ 834,810	$ 918,671

In Colombia in the year 2017 the majority of oil sales were with ten counterparties (year ended December 31, 2016 – ten counterparties) in the oil and gas industry and are subject to normal industry credit risks.

23. Commitments and Contingencies

a) Colombia

At December 31, 2017 performance guarantees are in place with the ANH and Ecopetrol for the Capachos and Aguas Blancas farm-in blocks. The guarantees are in the form of issued letters of credit totaling $142.6 million (December 31, 2016 - $148.7 million) to support the exploration work commitments in respect of the 20 blocks in Colombia.

At December 31, 2017 EDC has provided the Company's bank with performance security guarantees to support approximately $116.1 million (December 31, 2016 - $126.4 million) of the letters of credit issued on behalf of Parex. The EDC guarantees have been secured by a general security agreement issued by Parex in favour of EDC. The letters of credit issued to the ANH and Ecopetrol are reduced from time to time to reflect completed work on an ongoing basis. At December 31, 2017, there are an additional $26.4 million (December 31, 2016 - $21.3 million) letters of credit that are provided by a Latin American bank on an unsecured basis.

The value of the Company's exploration commitments as at December 31, 2017 in respect of the Colombia blocks are estimated to be as follows:

(000s)		
2018	$	57,541
2019		104,438
Thereafter		—
	$	161,979

b) Operating leases

In the normal course of business, Parex has entered into arrangements and incurred obligations that will impact the Company's future operations and liquidity. These commitments include leases for office space and accommodations.

The existing minimum lease payments for office space and accommodations at December 31, 2017 are as follows:

(000s)		Total	2018	2019	2020	2021	Thereafter
Office and accommodations	$	7,202	1,684	979	1,243	963	2,333

c) Legal settlement

In the second quarter of 2017 Parex came to an agreement in respect of the Company's indirect subsidiary Ramshorn International Limited ("Ramshorn") litigation in Texas, Bermuda and Canada. Ramshorn was acquired in 2012 by Parex and holds a 45% working interest in Block LLA-34. (Refer to the Company's AIF dated March 21, 2017 for additional background information). Parex and the plaintiff's bankruptcy trustee agreed to settle all outstanding litigation in all jurisdictions for an amount of $15.0 million. Parex accrued the amount at June 30, 2017 and the payment was completed in July 2017. The settlement removes all outstanding and any potential future litigation regarding the Plaintiff and potential liability associated with the Ramshorn's ownership of Block LLA-34 and costs of defending the actions in multiple jurisdictions.

24. Related Party Disclosures

a) Significant Subsidiaries

The consolidated financial statements include the financial statements of Parex Resources Inc. at December 31, 2017 and 2016. Transactions between subsidiaries are eliminated upon consolidation.

b) Compensation of Key Management Personnel

Key management personnel compensation, including directors, is as follows:

For the year ended December 31,		**2017**		2016
Salaries, directors fees and other benefits	**$**	**2,980**	$	2,432
Share-based compensation(1)		**7,430**		4,117
	$	**10,410**	$	6,549

(1) Non-cash share-based compensation expense for the year.

At December 31, 2017 key management personnel are comprised of the Company's directors and seven executives. As at December 31, 2017, there is a $8.2 million commitment relating to change of control or termination of employment of the seven executives (December 31, 2016 - $6.3 million for the five executives).

c) Other transactions

During the years ended December 31, 2017 and 2016, the Company rented office space to certain directors of the Company at market rental rates. The Company earned $17 thousand dollars during the year ended December 31, 2017 (year ended December 31, 2016 - $25 thousand dollars) in rental income from these related parties. The lease was terminated in September 2017 and at December 31, 2017 and 2016, $nil of this balance was outstanding.

Other than the above noted transaction, the Company did not have any related party transactions with entities outside the consolidated group for the years ended December 31, 2017 and 2016.

DIRECTORS

Wayne K. Foo
Chairman of the Board

Curtis D. Bartlett

Lisa Colnett

Robert J. Engbloom

Bob MacDougall

Glenn McNamara

Ron D. Miller

Carmen Sylvain

David R. Taylor

Paul D. Wright

OFFICERS & SENIOR EXECUTIVES

David R. Taylor
President and Chief Executive Officer

Kenneth G. Pinsky
Chief Financial Officer & Corporate Secretary

Stu R. Davie
Vice President Corporate Services

Lee DiStefano
President, Parex Colombia & Country Manager

Ryan W. Fowler
Sr. Vice President, Exploration & Business Development

Eric Furlan
Chief Operating Officer

Michael Kruchten
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ABBREVIATIONS

Oil and Natural Gas Liquids

bbls	barrels
mbbls	one thousand barrels
mmbbls	one million barrels
NGLs	natural gas liquids
bbls/d	barrels of oil per day
mbbls/d	one thousand barrels per day
BOE or boe	barrel of oil equivalent, using the conversion factor of 6 Mcf: 1 bbl
mboe	one thousand barrels of oil equivalent
mmboe	one million barrels of oil equivalent
bfpd	barrels of fluid per day
boe/d	barrels of oil equivalent per day
bopd	barrels of oil per day
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day

Other

WTI	West Texas Intermediate
Brent	Brent Ice

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

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") of the financial condition and results of operations of Parex Resources Inc. ("Parex" or the "Company") for the three months and year ended December 31, 2017 and 2016 is dated March 5, 2018 and should be read in conjunction with the audited consolidated financial statements for the years ended December 31, 2017 and 2016. The audited consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS" or "GAAP") as issued by the International Accounting Standards Board.

Additional information related to Parex and factors that could affect the Company's operations and financial results are included in reports on file with Canadian securities regulatory authorities, including the Company's Annual Information Form dated March 17, 2016 (the "AIF"), and may be accessed through the SEDAR website at www.sedar.com.

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

Company Profile

Parex is an oil and gas company actively engaged in crude oil exploration, development and production in Colombia. Headquartered in Calgary, Canada, Parex, through its foreign subsidiaries, holds interests in onshore exploration and production blocks totaling approximately 1,574,279 gross acres. The common shares of the Company trade on the Toronto Stock Exchange ("TSX") under the symbol PXT.

Abbreviations

Refer to the final page of the MD&A for commonly used abbreviations in the document. Refer to page 22 for Reserves Information, page 20 for the Advisory on Forward-Looking Statements and page 22 for Non-GAAP Terms used.

2017 Highlights

- Annual oil and natural gas production in 2017 averaged 35,541 boe/d, of which 99% was crude oil, an increase of 20 percent over 2016;
- Released an independently evaluated reserves assessment prepared by GLJ Petroleum Consultants Ltd. ("GLJ") with proved plus probable reserves growth of 45 percent over 2016, increasing to 162.2 million barrels of oil equivalent (net company working interest, 99% crude oil) at December 31, 2017 from 111.9 million barrels of oil equivalent (net company working interest) at December 31, 2016 and achieved proved plus probable reserve replacement of 488 percent with total 2017 gross reserve additions of 63.3 million barrels of oil equivalent;
- Finding, Development and Acquisition costs ("FD&A") for the year ended December 31, 2017 were $7.46/boe for proved developed producing reserves and $4.71/boe for proved plus probable reserves including future development capital;
- Recorded net income of $155.1 million ($1.01 per share basic) for the year ended December 31, 2017 as compared to a $46.4 million net loss ($0.31 net loss per share basic) in the year ended December 31, 2016;
- Generated year end funds flow from operations of $279.5 million ($1.81 per share basic), a 94 percent increase from the year ended December 31, 2016 of $144.1 million ($0.95 per share basic) with a 21 percent increase in Brent reference pricing year over year;
- Capital expenditures including property acquisitions were $212.3 million compared to $111.7 million for the year ended December 31, 2016. Capital expenditures were funded from funds flow from operations, with excess funds flow increasing working capital;
- Increased net working capital to $163.4 million at December 31, 2017 compared to a working capital position of $93.3 million at December 31, 2016, and exited 2017 with no bank or term debt; and
- Participated in drilling 38 gross wells in Colombia resulting in 30 oil wells, 2 disposal wells, 5 abandoned wells and 1 untested well, for a success rate of 86 percent.

Three Months Ended December 31, 2017 ("fourth quarter or Q4") Highlights

- Achieved a record quarterly oil and natural gas production of 39,007 boe/d, an increase of 26% over the fourth quarter of 2016 and 10% higher than the 2017 average oil and natural gas production;
- Earned net income of $55.9 million ($0.36 per share basic) compared to a net loss of $45.4 million ($0.30 loss per share basic) in the fourth quarter of 2016;
- Generated funds flow from operations of $93.9 million ($0.61 per share basic) a 81 percent increase compared to $51.8 million ($0.34 per share basic) in the comparative period; and
- Utilized a portion of funds flow from operations in excess of capital expenditures to purchase 539,100 of the Company's common shares at an average price of Cdn$16.53 pursuant to the Company's normal course issuer bid program.

Financial Summary

	For the three months ended December 31,		For the year ended December 31,		
(Financial figures in 000s except per share amounts)	**2017**	2016	**2017**	2016	2015
Average daily oil production (bbl/d)	**38,553**	30,762	**35,212**	29,473	27,434
Average daily natural gas production (mcf/d)	**2,724**	1,722	**1,974**	1,452	—
Average oil and natural gas production (boe/d)	**39,007**	31,049	**35,541**	29,715	27,434
Production split (% crude oil)	**99**	99	**99**	99	100
Realized sales price (/boe)	**$ 56.90**	$ 44.84	**$ 50.35**	$ 37.63	$ 46.59
Operating netback (/boe) [1]	**$ 35.39**	$ 24.40	**$ 29.69**	$ 18.03	$ 21.70
Oil and natural gas revenue	**$ 203,930**	$ 131,858	**$ 659,407**	$ 445,488	$ 521,089
Funds flow from operations	**$ 93,861**	$ 51,791	**$ 279,528**	$ 144,131	$ 130,271
Per share – basic	**0.61**	0.34	**1.81**	0.95	0.90
Per share – diluted [1]	**0.59**	0.33	**1.78**	0.94	0.90
Net income (loss)	**$ 55,921**	$ (45,440)	**$ 155,078**	$ (46,444)	$ (44,621)
Per share – basic	**0.36**	(0.30)	**1.01**	(0.31)	(0.31)
Per share – diluted	**0.35**	(0.30)	**0.99**	(0.31)	(0.31)
Capital Expenditures	**$ 66,341**	$ 66,980	**$ 212,346**	$ 111,722	$ 125,482
Total assets (end of period)	**$ 1,121,908**	$ 918,671	**$ 1,121,908**	$ 918,671	$ 957,966
Working capital surplus (end of period) [2]	**$ 163,401**	$ 93,290	**$ 163,401**	$ 93,290	$ 76,708
Bank debt (end of period) [3]	**$ —**	$ —	**$ —**	$ —	$ —
Weighted average shares outstanding (000s)					
Basic	**154,812**	152,778	**154,209**	152,184	145,018
Diluted	**158,740**	155,842	**157,272**	154,418	145,507
Outstanding shares (end of period) (000s)	**154,742**	152,990	**154,742**	152,990	151,489

(1) Non-GAAP terms. See "Non-GAAP Terms" on page 22.

(2) Working capital calculation does not take into consideration the undrawn amount available under the syndicated bank credit facility.

(3) Syndicated bank credit facility borrowing base of $100.0 million as at December 31, 2017, voluntarily reduced from the borrowing base of $175.0 million at December 31, 2016.

Strategy

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

Principal Properties

As at December 31, 2017, the Company's principal land holdings and interests in exploration and production blocks held by its subsidiaries were as follows:

	Working Interest	Gross Acres	Net Acres
Colombia Llanos Basin			
Operated Properties			
LLA-16, 29 and 30	100 %	197,294	197,294
Los Ocarros	100 %	31,066	31,066
Cabrestero	100 %	7,605	7,605
LLA-40	100 %	82,422	82,422
LLA-26	100 %	93,376	93,376
Capachos(1)	50 %	64,073	32,037
LLA-32	87.5 %	57,040	49,910
LLA-10(1)	50 %	189,544	94,772
Non-Operated Properties			
LLA-34	55 %	68,382	37,610
Balay	10 %	4,500	450
Colombia Magdalena Basin			
Operated Properties			
VMM-11(2)	100 %	116,826	116,826
Morpho	100 %	51,420	51,420
VIM-1	100 %	223,651	223,651
VMM-9	100 %	152,412	152,412
Aguas Blancas(1)	50 %	13,386	6,693
De Mares (1)	50 %	174,387	87,194
Playon(1)	50 %	43,200	21,600
Sogamoso(1)	100 %	3,695	3,695
Total		1,574,279	1,290,033

(1) Lands are subject to farm-in-agreement earning terms and/or regulatory approval.
(2) The Company plans to relinquish VMM-11 land in 2018.

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

2018 Guidance

Parex' guidance for 2018, as previously press released on November 7, 2017 is as follows:

Annual production (boe/d, 99% oil)	41,000-43,000
Capital Expenditures (millions)	
Maintenance (14 gross wells and related facilities)	$90
Growth Capital (30-36 gross wells and related facilities)	$170-200
Total (millions)	$260-$290

We expect planned capital expenditures to be fully funded by funds flow from operations, with working capital being retained for additional growth opportunities and to buy back outstanding shares as deemed appropriate.

Financial and Operational Results

Consolidated Results of Operations

Parex' oil and gas operations are conducted in Colombia with head office functions conducted in Canada.

	For the three months ended December 31,		For the year ended December 31,	
	2017	2016	**2017**	2016
Average daily production				
Crude oil (bbl/d)	**38,553**	30,762	**35,212**	29,473
Natural gas (mcf/d)	**2,724**	1,722	**1,974**	1,452
Total (boe/d)	**39,007**	31,049	**35,541**	29,715
Production split (% crude oil production)	**99**	99	**99**	99
Average daily sales of oil and natural gas				
Produced crude oil (bbl/d)	**38,203**	26,108	**35,181**	29,593
Purchased crude oil (bbl/d)	**300**	714	**372**	1,059
Produced natural gas (mcf/d)	**2,724**	1,722	**1,974**	1,452
Total (boe/d)	**38,957**	27,110	**35,884**	30,894
Operating netback (000s)				
Oil and gas sales excluding risk management contracts	**$ 203,930**	$ 131,858	**$ 659,407**	$ 445,488
Royalties	**(19,852)**	(10,360)	**(58,540)**	(34,327)
Net revenue	**184,078**	121,498	**600,867**	411,161
Production expense	**(19,226)**	(15,364)	**(69,169)**	(53,250)
Transportation expense	**(37,694)**	(31,488)	**(141,475)**	(130,930)
Purchased oil expense	**(1,425)**	(4,170)	**(5,653)**	(25,109)
Operating netback(1)	**$ 125,733**	$ 70,476	**$ 384,570**	$ 201,872
Operating netback (per boe) (1)				
Oil and gas sales (1)	**$ 56.90**	$ 44.84	**$ 50.35**	$ 37.63
Royalties	**(5.58)**	(3.75)	**(4.52)**	(3.14)
Net revenue	**51.32**	41.09	**45.83**	34.49
Production expense	**(5.41)**	(5.56)	**(5.34)**	(4.88)
Transportation expense	**(10.52)**	(11.13)	**(10.80)**	(11.58)
Operating netback	**$ 35.39**	$ 24.40	**$ 29.69**	$ 18.03

(1) Refer to page 21 "Non-GAAP Terms" for a description and details of the operating netback calculation.

The average realized sales price for the three months and year ended December 31, 2017 was $56.90/boe ($44.84/boe - three months ended December 31, 2016) and $50.35/boe ($37.63/boe - year ended December 31, 2016) compared to $48.07/boe for the third quarter of 2017.

Royalty charges for the three months and year ended December 31, 2017 were $5.58/boe ($3.75/boe - three months ended December 31, 2016) and $4.52/boe ($3.14/boe - year ended December 31, 2016) compared to $3.94/boe for the third quarter of 2017.

Production expense for the three months and year ended December 31, 2017 was $5.41/boe ($5.56/boe - three months ended December 31, 2016) and $5.34/boe ($4.88/boe - year ended December 31, 2016) compared to $5.51/boe for the third quarter of 2017.

Transportation expense for the three months and year ended December 31, 2017 was $10.52/boe ($11.13/boe - three months ended December 31, 2016) and $10.80/boe ($11.58/boe - year ended December 31, 2016) and compared to $10.72/boe for the third quarter of 2017.

The Company's operating netback for the three months and year ended December 31, 2017 was $35.39/boe ($24.40/boe - three months ended December 31, 2016) and $29.69/boe ($18.03/boe - year ended December 31, 2016) compared to $27.90/boe for the third quarter of 2017.

Overall the price of the Company's benchmark Brent crude increased by $9.29/bbl in the fourth quarter as compared to the third quarter of 2017 while the operating netback increased by $7.49/boe in the same period, mainly as a result of increased royalties and a slight increase in the differential between the Company's realized price and the Brent crude reference price.

Parex recorded $67.2 million of free funds flow in 2017, and as a result improved the Company's working capital surplus to $163.4 million at December 31, 2017.

Colombian Oil and Natural gas Sales

a) Average Daily Production and Sales Volumes (boe/d)

	For the three months ended December 31,		For the year ended December 31,	
	2017	2016	**2017**	2016
Block LLA-34 (Tigana, Jacana, Tua, Tarotaro & Tilo fields)	**28,319**	20,316	**25,271**	18,149
Block Cabrestero (Bacano, Akira and Kitaro fields)	**5,071**	2,576	**3,893**	2,784
Block LLA-26 (Rumba field)	**2,154**	4,044	**3,075**	4,383
Block LLA-32 (Kananaskis, Calona, and Carmentea fields)	**1,146**	1,065	**1,006**	1,376
Other blocks	**1,863**	2,761	**1,967**	2,781
Total Crude Oil Production	**38,553**	30,762	**35,212**	29,473
Natural gas production	**454**	287	**329**	242
Total crude oil and natural gas production	**39,007**	31,049	**35,541**	29,715
Crude oil inventory (build) draw	**(350)**	(4,653)	**(29)**	120
Average daily sales of produced oil and natural gas	**38,657**	26,396	**35,512**	29,835
Purchased oil	**300**	714	**372**	1,059
Sales Volumes	**38,957**	27,110	**35,884**	30,894

Oil and natural gas production for the fourth quarter of the year averaged 39,007 boe/d, an increase of approximately 8% from the third quarter 2017 average and a 26% increase from the fourth quarter of 2016. The increase in sales volumes in the fourth quarter of 2017 compared to the prior quarter of 2016 is a result of increased production and crude oil inventory returning to historical levels.

b) Average Reference and Realized Prices

	For the three months ended December 31,		For the year ended December 31,	
	2017	2016	**2017**	2016
Reference Prices				
Brent ($/bbl)	**61.46**	51.13	**54.75**	45.12
WTI ($/bbl)	**55.33**	49.16	**50.84**	43.28
Vasconia ($/bbl)	**57.30**	46.17	**50.75**	39.64
Average Realized Prices				
Realized sales price ($/boe)	**56.90**	44.84	**50.35**	37.63
Realized oil price risk management gain (loss) ($/boe)	**(0.39)**	(0.49)	**(0.18)**	(0.60)
Realized sales price after risk management gain (loss) ($/boe)	**56.51**	44.35	**50.17**	37.03
Realized price (differential) to Brent crude ($/boe)	**(4.56)**	(6.29)	**(4.40)**	(7.49)

During Q4 2017, the differential between Brent reference pricing and the Company's realized sale price was $4.56/boe excluding gains and losses from commodity price risk management contracts. The differential to Brent crude during Q4 was approximately $0.50/boe wider than the previous two quarters of 2017 (see below).

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

Average price for the period	**Q4 2017**	Q3 2017	Q2 2017	Q1 2017	Q4 2016
Brent ($/bbl)	**61.46**	52.17	50.87	54.61	51.13
Vasconia ($/bbl)	**57.30**	49.15	47.10	49.57	46.17
Parex realized sales price ($/boe)	**56.90**	48.07	46.84	48.72	44.84
Parex realized price (differential) to Brent crude ($/boe)	**(4.56)**	(4.10)	(4.03)	(5.89)	(6.29)
Parex realized price (differential) to Vasconia crude ($/boe)	**(0.40)**	(1.08)	(0.26)	(0.85)	(1.33)

Differences between Parex' realized price and Vasconia crude price is mainly related to quality adjustments and timing of oil sales compared to quarter averages. The differential between Vasconia crude pricing and Brent crude pricing also affects Parex' realized sales price and is set in liquid global markets and therefore attributed to factors that are beyond the Company's control. The differential over the last three quarters has been in the $4.00/boe range. Parex has conservatively budgeted a $5.00/boe discount to Brent for 2018.

c) Natural Gas Revenue and Realized Prices

	For the three months ended December 31,		For the year ended December 31,	
	2017	2016	**2017**	2016
Natural gas revenue ($000s)	**$ 1,749**	1,058	**$ 4,939**	3,436
Realized sales price ($/Mcf)	**6.98**	6.68	**6.84**	6.47

Parex natural gas revenues represent less than 1% of oil and natural gas sales revenue.

d) Oil and Natural Gas Revenue

2017 oil and natural gas revenue increased by $213.9 million or 48 percent as reconciled in the table below to 2016:

($000s)		
Oil and natural gas revenue, year ended December 31, 2016	**$**	**445,488**
Sales volume of produced oil, an increase of 19% (5,590 bbl/d)		**76,778**
Sales volume of purchased oil, a decrease of 65% (687 bbl/d)		**(9,436)**
Sales price increase of 34%		**143,387**
Sales volume and price change of produced natural gas, an increase of 36% (87 boe/d)		**3,190**
Oil and natural gas revenue, year ended December 31, 2017	**$**	**659,407**

e) Colombian Crude Oil Inventory in Transit

($000s) For the years ended December 31,	**2017**	2016
Crude oil in transit	**$ 3,038**	$ 2,834

At December 31, 2017, the Company had 103,018 bbls (December 31, 2016 - 92,306 bbls) of crude oil inventory in transit, which was injected into Colombian pipelines. The inventory was valued based on direct and indirect expenditures (including production costs, transportation costs, depletion expense and royalty expense) at approximately $29/bbl ($31/bbl - 2016) incurred in bringing the crude oil to its existing condition and location. The cost per bbl of crude oil inventory has decreased largely due to a reduction in depletion expense, offset slightly by an increased royalty cost per bbl from the prior period.

A reconciliation of quarter to quarter crude oil inventory movements is provided below:

(mbbls) For the periods ended	**Dec. 31, 2017**	Sep. 30, 2017	June 30, 2017	March 31, 2017
Crude oil inventory in transit - beginning	**70.9**	44.1	3.1	92.3
Oil production	**3,546.8**	3,301.7	3,095.1	2,908.5
Oil sales	**(3,542.2)**	(3,298.8)	(3,079.1)	(3,056.9)
Purchased oil	**27.5**	23.9	25.0	59.2
Crude oil inventory in transit - end	**103.0**	70.9	44.1	3.1
% of period production	**2.9**	2.1	1.4	—

Crude oil inventory build and draw down from period to period are subject to factors that the Company does not control such as timing of the number of shipments from storage to export. Crude oil inventory as a percentage of quarterly production at December 31, 2017 was 2.9%.

f) Purchased Oil

	For the three months ended December 31,		For the year ended December 31,	
	2017	2016	**2017**	2016
Purchased oil expense ($000s)	**$ 1,425**	$ 4,170	**$ 5,653**	$ 25,109

Purchased oil expense for the three months and year ended December 31, 2017 was $1.4 million and $5.7 million as compared to $0.9 million in the preceding quarter and $4.2 million and $25.1 million for the three months and year ended December 31, 2016. Purchased oil expense has decreased as a result of a decrease in oil blending operations. Transportation costs are incurred by the Company to transport purchased oil to sale delivery points.

Colombian Royalties

	For the three months ended December 31,		For the year ended December 31,	
	2017	2016	**2017**	2016
Royalties ($000s)	**$ 19,852**	$ 10,360	**$ 58,540**	$ 34,327
Per unit ($/boe)	**5.58**	3.75	**4.52**	3.14
Percentage of sales(1)	**9.7**	9.3	**9.2**	8.1

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

For the three months and year ended December 31, 2017 royalties as a percentage of sales was 9.7% and 9.2%, an increase from 9.3% and 8.1% in the three months and year ended December 31, 2016. The third quarter of 2017 royalty as a percentage of sales was 8.2%. The increase in royalties as a percentage of oil sales is a result of an increase in WTI crude oil prices which effects the high price royalty (HPR) calculation. The HPR is applicable currently on the following oil fields, Tua, Tigana, Jacana, Las Maracas, and Kona.

The HPR comes into effect when accumulated production of any production area, inclusive of royalty volumes, exceeds 5 million barrels, and in the event international reference prices exceed pricing determined in the contract. The calculation is described as a "High Price Share" in the Company's AIF, which may be accessed through the SEDAR website at www.sedar.com.

Colombian Production Expense

	For the three months ended December 31,		For the year ended December 31,	
	2017	2016	**2017**	2016
Production expense ($000s)	**$ 19,226**	$ 15,364	**$ 69,169**	$ 53,250
Per unit ($/boe)	**5.41**	5.56	**5.34**	4.88

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

	For the three months ended December 31,		For the year ended December 31,	
	2017	2016	**2017**	2016
Per unit ($/boe) – based on sales volumes – operated[1]	**8.84**	6.93	**8.06**	5.74
Per unit ($/boe) – based on sales volumes – non-operated[1]	**4.14**	4.79	**4.27**	4.31

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

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

Production expense for the fourth quarter of $5.41/boe was slightly lower in comparison to the third quarter of $5.51/boe. Operated properties production expense in the fourth quarter was $8.84/boe compared to $7.61/boe for the third quarter and non-operated properties production expense was $4.14/boe for the fourth quarter compared to $4.61/boe for the third quarter. The quarter over quarter increase in the operated properties production expense relates to an increase in well services performed on operated blocks. The quarter over quarter decrease in the non-operated properties production expense relates to an increase in fixed cost absorption as a result of increased non-operated production levels.

Production expense for the year ended December 31, 2017 is $5.34/boe compared to $4.88/boe for the year ended December 31, 2016. The increase is primarily due to increased water handling and well service costs on operated fields as compared to the prior year.

Colombian Transportation Expense

	For the three months ended December 31,		For the year ended December 31,	
	2017	2016	**2017**	2016
Transportation expense ($000s)	**$ 37,694**	$ 31,488	**$ 141,474**	$ 130,929
Per unit ($/boe)	**10.52**	11.13	**10.80**	11.58

For the three months ended December 31, 2017, the cost of transportation of $10.52/boe has decreased compared to the third quarter cost of $10.72/boe and the comparative period of $11.13/boe. The decrease from the comparative period is a result of decreased pipeline tariff fees and decreased trucking costs.

On a year to date basis transportation expense has decreased to $10.80/boe from $11.58/boe in the comparative period. The main reason for this decrease relates to increased available pipeline capacity which reduced the amount of oil being trucked for export which generally comes at a higher cost per barrel than pipeline tariff fees.

General and Administrative Expense ("G&A")

	For the three months ended December 31,		For the year ended December 31,	
($000s)	**2017**	2016	**2017**	2016
Gross G&A	**$ 10,747**	$ 8,976	**$ 39,151**	$ 35,834
G&A recoveries	**(334)**	(574)	**(855)**	(1,072)
Capitalized G&A	**(1,406)**	(1,441)	**(4,207)**	(3,948)
Net G&A expense	**$ 9,007**	$ 6,961	**$ 34,089**	$ 30,814
Per unit ($/boe) [1]	**2.51**	2.44	**2.63**	2.83

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

Net G&A was $9.0 million and $34.1 million for the three months and year ended December 31, 2017 compared to $7.0 million and $30.8 million for the same periods in 2016. Gross G&A was $10.7 million and $39.2 million for the three months and year ended December 31, 2017 (three months and year ended December 31, 2016 - $9.0 million and $35.8 million). Both Gross G&A and Net G&A has increased from the prior year due to one-time costs associated with system and process improvement projects and general salary increases in Colombia. In the third quarter of 2017 net G&A was $8.9 million which is in line with the fourth quarter of 2017 of $9.0 million.

On a units of production basis net G&A for the year has decreased marginally from the comparative year.

The Company's G&A expense is mainly denominated in local currencies of COP and Cdn dollar, refer to the foreign exchange sensitivity on page 10 to see the affects of foreign exchange sensitivities on net G&A per boe.

Stock-Based Compensation and Share Appreciation Rights Expense

	For the three months ended December 31,		For the year ended December 31,	
($000s)	**2017**	2016	**2017**	2016
Equity settled share-based compensation	**$ 3,744**	$ 3,807	**$ 18,381**	$ 12,818
Cash settled share-based compensation	**5,884**	1,856	**9,707**	13,382
Share appreciation rights expense (recoveries)	**(1,168)**	(455)	**(1,228)**	(455)
Total expense	**$ 8,460**	$ 5,208	**$ 26,860**	$ 25,745

Share-based compensation expense was $26.9 million for the twelve months ended December 31, 2017 compared to $25.7 million for the same period in 2016.

Equity settled share-based compensation expense was $3.7 million for the three months ended December 31, 2017 compared to $3.8 million for the same period in 2016. Equity settled share-based compensation includes the Company's stock option plan and the restricted share unit ("RSU") plan pursuant to which RSUs and performance based RSUs ("PSUs") may be awarded. Overall the number of stock options outstanding has decreased from December 31, 2016 while the number of RSUs and PSUs outstanding has increased as stock options have become a lesser factor in the Company's compensation strategy.

Cash settled share-based compensation relates to the Company's cash settled incentive plans for its Colombian based employees and the Company's non-employee directors and includes share appreciation rights ("SARs"), cash settled restricted share units ("CRSUs") and deferred share units ("DSUs"). The CRSU plan is a new cash settled plan that will replace the current SAR plan as granted SAR's vest, and are exercised. There will be no SAR grants going foward. For the three months ended December 31, 2017 there was an expense of $5.9 million related to cash settled incentive plans compared to $1.9 million expense for the same period in 2016. The increase is mainly due to an issuance of new CRSUs under the plan, an increased Black-Scholes value in the current year as compared to the prior year and the SARs paid. Obligations for payments of cash under the Company's cash settled incentive plans are accrued as expense over the vesting period based on the fair value of the units as described in note 15 of the consolidated financial statements for the year ended December 31, 2017. As at December 31, 2017, the total cash settled incentive plans liability accrued is $16.6 million (December 31, 2016 - $13.5 million).

Depletion, Depreciation and Amortization Expense ("DD&A")

	For the three months ended December 31,		For the year ended December 31,	
	2017	2016	**2017**	2016
DD&A ($000s) total	**$ 19,668**	$ 23,133	**$ 98,738**	$ 115,777
Per unit ($/boe)(1)	**5.48**	8.10	**7.61**	10.65

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

Fourth quarter 2017 DD&A was $19.7 million compared to $23.1 million for the same period in 2016. For the twelve months ended December 31, 2017 DD&A was $98.7 million ($7.61/boe) as compared to $115.8 million ($10.65/boe) for the prior year.

For the fourth quarter of 2017, future development costs of $397.3 million (three months ended December 31, 2016 - $253.2 million) were included in the depletion calculation. Fourth quarter 2017 DD&A of $5.48/boe is lower than the comparative period of $8.10/boe. This decrease is due to the significant increase in proved and probable reserves, and a change in the CGU production mix from the prior comparative period.

Foreign Exchange

	For the three months ended December 31,		For the year ended December 31,	
	2017	2016	**2017**	2016
Foreign exchange loss ($000s)	**$ 256**	$ 1,769	**$ 462**	$ 1,485
Foreign Exchange Rates				
USD$/CAD$	**1.27**	1.33	**1.30**	1.32
USD$/Colombian peso	**2,986**	3,015	**2,951**	3,051

The Company's main exposure to foreign currency risk relates to the pricing of foreign currency denominated in Canadian dollars and Colombian pesos, as the Company's functional currency is the US dollar. The Company has exposure in Colombia and Canada on costs, such as capital expenditures, local wages, royalties and income taxes, all of which may be denominated in local currencies. The main driver of foreign exchange loss and gain recorded on the consolidated statements of comprehensive income (loss) is the Colombian Peso denominated tax withholdings receivable and income tax payable balances in Colombia. For the three months ended December 31, 2017, a total foreign exchange loss of $0.3 million was recorded and for the full year 2017 a loss of $0.5 million was recorded. The timing of payment settlements, accruals and their adjustments have impacts on foreign exchange gains/losses. Unrealized foreign exchange gains and losses may be reversed in the future as a result of fluctuations in exchange rates and are recorded in the Company's consolidated statement of comprehensive income (loss).

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

Foreign Exchange Sensitivity Analysis

		$/boe Impact of change in local currency/ $USD exchange rate	
Cost component	**Estimated percent of cost denominated in local currency**	10% appreciation of local currency	10% depreciation of local currency
Production expense	80%	$ 0.43	$ (0.43)
Transportation expense	50%	$ 0.53	$ (0.53)
G&A expense	100%	$ 0.25	$ (0.25)

The table above displays the estimated per boe impact of a change in Parex' local currencies and the effect on Parex' key cost components. The component impact in $/boe terms uses Q4 2017 per boe costs. This analysis ignores all other factors impacting cost structure including efficiencies, cost reduction strategies, etc.

Net Finance (Income) Expense

	For the three months ended December 31		For the year ended December 31,	
	2017	2016	**2017**	2016
For the year ended December 31,				
Bank charges and credit facility fees	**$ 5**	$ 339	**$ 2,742**	$ 2,614
Accretion on decommissioning and environmental liabilities	**999**	528	**3,965**	1,831
Colombian net wealth tax	**—**	—	**894**	2,228
Interest and other income	**(869)**	(298)	**(2,369)**	(1,260)
Gain on property acquisition	**(5,002)**	—	**(5,002)**	—
Bad debt expense	**1,463**	—	**1,463**	—
Loss on disposition of tangible assets	**605**	—	**605**	—
Loss on overlifted oil volumes	**—**	3,610	**—**	3,610
Net finance (income) expense	**$ (2,799)**	$ 4,179	**$ 2,298**	$ 9,023

	For the three months ended December 31,		For the year ended December 31,	
	2017	2016	**2017**	2016
Non-cash finance (income) expense	**$ (3,398)**	$ 4,138	**$ (432)**	$ 5,441
Cash finance expense	**599**	41	**2,730**	3,582
Net finance (income) expense	**$ (2,799)**	$ 4,179	**$ 2,298**	$ 9,023

Bank charges and credit facility fees relate to bank taxes paid in Colombia and the standby fees related to the undrawn credit facility. The non-cash components of net finance expense include the accretion on decommissioning and environmental liabilities, gain on property acquisition, bad debt expense, loss on disposition of tangible assets and loss on overlifted oil volumes line items.

The gain on property acquisition primarily relates related to the purchase of additional working interest in Block LLA-32 and LLA-40 as well as the remeasurement of the pre-existing 50% interest in Block LLA-40. Refer to note 9 of the Company's December 31, 2017 consolidated financial statements.

The loss on overlifted oil volumes recorded in the comparative period fourth quarter of 2016 represents a non-cash loss on non-cash revenue earned on the return of oil volumes in October 2016 that were overlifted from the Ocensa pipeline at September 30, 2016. For further information please refer to Note 3 (g) in the Company's December 31, 2016 consolidated financial statements.

Risk Management

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

Parex has elected not to apply IFRS prescribed "hedge accounting" rules and, accordingly, pursuant to IFRS the fair value of the financial contracts is recorded at each period-end. The fair value may change substantially from period to period depending on commodity and foreign exchange forward strip prices for the financial contracts outstanding at the balance sheet date. The change in fair value from period-end to period-end is reflected in the earnings for that period. As a result, earnings may fluctuate considerably based on the period-ending commodity and foreign exchange forward strip prices.

Risk Management Contracts – Brent Crude

Period Hedged	**Reference**	**Volume bbls/d**	**Sold Put**	**Purchased Put**	**Sold Call**	**Premium**
January 1, 2017 to February 28, 2017	ICE Brent	5,000	$ 44.00	$ 48.00	$ 63.35	$ —
January 1, 2017 to March 31, 2017	ICE Brent	5,000	$ 40.00	$ 45.00	$ 59.40	$ —
April 1, 2017 to June 30, 2017	ICE Brent	5,000	$ 40.00	$ 45.00	$ 64.00	$ —
April 1, 2017 to September 30, 2017	ICE Brent	5,000	$ 40.00	$ 50.00	$ —	$ 1.30
July 1, 2017 to September 30, 2017	ICE Brent	5,000	$ 45.00	$ 50.00	$ —	$ 0.95
October 1, 2017 to December 31, 2017	ICE Brent	5,000	$ 40.00	$ 45.00	$ 61.75	$ —
January 1, 2018 to March 31, 2018	ICE Brent	5,000	$ 47.00	$ 50.00	$ —	$ 0.40
January 1, 2018 to March 31, 2018	ICE Brent	5,000	$ 47.00	$ 50.00	$ —	$ 0.25
January 1, 2018 to June 30, 2018	ICE Brent	5,000	$ 47.00	$ 50.00	$ —	$ 0.27

The table below summarizes the loss (gain) on the commodity risk management contracts that were in place during the three months and years ended December 31, 2017 and 2016:

	For the three months ended December 31,		For the year ended December 31,	
($000s)	**2017**	2016	**2017**	2016
Realized loss (gain) on commodity risk management contracts	**$ 1,137**	$ —	**$ 513**	$ (948)
Premiums paid on commodity risk management contracts	**248**	1,228	**1,875**	7,755
Unrealized loss (gain) on commodity risk management contracts	**(61)**	157	**(1,178)**	3,859
Total	**$ 1,324**	$ 1,385	**$ 1,210**	$ 10,666

Subsequent to December 31, 2017, Parex entered into the following crude oil risk management contracts:

Period Hedged	**Reference**	**Volume bbls/d**	**Sold Put**	**Purchased Put**	**Sold Call**	**Premium**
April 1, 2018 to September 30, 2018	ICE Brent	10,000	$ 50.00	$ 55.00	$ —	$0.40

The Company's net unrealized commodity price derivative gain on risk management contracts for the year ended December 31, 2017 was $1.2 million (December 31, 2016 - loss of $3.9 million). The net unrealized gain is primarily attributable to the Brent forward benchmark price decreasing since the time the derivative contracts were entered into. The realized loss on commodity risk management contracts including premiums paid was $0.2 million and $1.9 million for the three and twelve months ended December 31, 2017.

Income Tax

The components of tax expense for the three and twelve months ended December 31, 2017 and 2016 were as follows:

	For the three months ended December 31,		For the year ended December 31,	
($000s)	**2017**	2016	**2017**	2016
Current tax expense	**$ 15,492**	$ 3,971	**$ 44,020**	$ 5,628
Deferred tax (recovery)	**(17,217)**	(10,167)	**(28,806)**	(30,299)
Total tax (recovery) expense	**$ (1,725)**	$ (6,196)	**$ 15,214**	$ (24,671)

Current tax expense in the fourth quarter of 2017 was $15.5 million as compared to $4.0 million in the comparative three month period. In the current quarter tax expense as a percentage of consolidated cash flows before tax was 14%. For the full year 2017 the Company recorded $44.0 million of current tax as compared to $5.6 million in 2016. This increase relates to higher taxable income largely as a result of higher realized prices and the exhaustion of Colombian non-capital loss carry-forwards in 2017.

Deferred tax in the fourth quarter of 2017 was a recovery of $17.2 million and a recovery of $28.8 million for the year ended December 31, 2017 ($10.2 million and $30.3 million recovery for the three months and year ended December 31, 2016). The deferred tax recovery is a result of a narrowing of the book and tax basis in Colombian subsidiaries from the non-cash impairments recorded on E&E and the tax restructuring completed in the third quarter of 2017. Also having an impact was the recognition of deferred tax assets in Canada as a result of determining that it is now probable that the Company will realize the benefit of these assets.

2018 Current Tax Guidance

When the Company's 2018 Budget and Guidance was released on November 7, 2017 the estimated current tax expense under a Brent crude price scenario of $55/bbl for the full year was approximately $4.20/boe. With the increase in proved developed reserves as detailed in the released December 31, 2017 independent reserve report the Company now estimates that current tax expense will be approximately $5.00/boe at the $55/bbl Brent crude price scenario, all else being equal. Proved developed reserves is the measure used to calculate depletion for tax purposes in Colombia.

For 2018 the Company now expects the effective tax rate on consolidated before tax cash flow to be approximately 20-25% at Brent crude prices between $60-$70/bbl with potential variances based on timing and number of dry hole write-offs and ending 2018 proved developed reserves. The Company's historical effective current tax rate has been between 13-15%. The estimated increase in 2018 is due to increased before tax cash flows being in excess of projected capital expenditures, decreased tax depletion as a result of increased proved developed reserves, and Colombian non-capital losses being fully exhausted in 2017.

Capital Expenditures and Acquisitions

For the year ended December 31,	Colombia		Canada		Total	
($000s)	**2017**	2016	**2017**	2016	**2017**	2016
Acquisition of unproved properties	**$ 3,751**	$ 7,683	**$ —**	$ —	**$ 3,751**	$ 7,683
Geological and geophysical	**584**	12,774	**—**	—	**584**	12,774
Drilling and completion	**181,757**	73,550	**—**	—	**181,757**	73,550
Well equipment and facilities	**19,715**	12,010	**—**	—	**19,715**	12,010
Llanos Basin additional working interest acquisition	**5,697**	4,025	**—**	—	**5,697**	4,025
Other	**795**	1,554	**47**	126	**842**	1,680
Total capital expenditures and acquisitions	**$ 212,299**	$ 111,596	**$ 47**	$ 126	**$ 212,346**	$ 111,722

For the three months ended December 31,	Colombia		Canada		Total	
($000s)	**2017**	2016	**2017**	2016	**2017**	2016
Acquisition of unproved properties	**$ (325)**	$ 7,314	**$ —**	$ —	**$ (325)**	$ 7,314
Geological and geophysical	**613**	11,951	**—**	—	**613**	11,951
Drilling and completion	**59,066**	38,023	**—**	—	**59,066**	38,023
Well equipment and facilities	**612**	5,812	**—**	—	**612**	5,812
Llanos Basin additional working interest acquisition	**5,697**	4,025	**—**	—	**5,697**	4,025
Other	**659**	(145)	**19**	—	**678**	(145)
Total capital expenditures and acquisitions	**$ 66,322**	$ 66,980	**$ 19**	$ —	**$ 66,341**	$ 66,980

Capital Expenditures Summary

During the twelve months ended December 31, 2017 the Company incurred $212.3 million of capital expenditures compared to $111.7 million in the same period of 2016. During 2017 the Company drilled 38 wells (23.65 net), compared to 17 wells (11.55 net) in 2016.

During the year ended December 31, 2017 capital expenditures of $212.3 million were self funded from funds flow from operations of $279.5 million. The Company has maintained its ability to fund growth from cash flow since 2012, excluding the cost of a corporate acquisition completed in 2014.

In the fourth quarter of 2017 the Company drilled 10 wells (6.35 net) in Colombia compared to 10 wells (6.35 net) in the comparative period. Drilling and completion costs during the fourth quarter totaled $59.1 million, all of which related to drilling and completion and capitalized workover costs in Colombia. The Company increased its level of capital activity in the fourth quarter due to the increase in global oil prices providing additional funds flow. The Company also spent $5.7 million to acquire additional working interest in two Llanos Basin blocks, refer to the "Acquisition" section below.

Acquisitions

a) 2017 Llanos Basin additional working interest acquisition

On October 4, 2017, Parex through its subsidiaries acquired an additional 17.5% working interest in the Block LLA-32 and 50% working interest in Block LLA-40 in Colombia's Llanos Basin (the "Llanos 2017 Acquisition"). The Company paid total net consideration of $5.0 million. The Llanos 2017 Acquisition increased the Company's working interest in Block LLA-32 to 87.5% and Block LLA-40 to 100%.

The consolidated statement of comprehensive income (loss) includes results of operation of the Llanos 2017 Acquisition since the closing date of October 4, 2017. There were no transaction costs associated with the Llanos Acquisition.

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

Assets acquired and liabilities assumed		
PP&E	$	11,137
Decommissioning and environmental liabilities		(2,537)
	$	**8,600**
Consideration for the acquisition		
Cash paid	$	5,697
Settlement of pre-existing relationship		(705)
Total net consideration paid	**$**	**4,992**
Gain on acquisition	**$**	**3,608**

In addition to the $3.6 million gain on acquisition above, the Company recorded a $1.4 million gain on the remeasurement of the pre-existing 50% interest in Block LLA-40. Both gains have been recorded in the financial statement line item "Finance Income" in the Consolidated Statement of Comprehensive Income (Loss). Refer to Note 11 of the Company's consolidated financial statements for the year ended December 31, 2017.

The pro forma results for year ended December 31, 2017 are shown below, as if the Llanos 2017 Acquisition had occurred on January 1, 2017. Pro forma results are not indicative of actual results or future performance.

Oil sales	$	7,749
Net income	$	2,879
Basic net income per share	$	0.02
Diluted net income per share	$	0.02

The consolidated statement of comprehensive income (loss) for the year ended December 31, 2017 includes $2.1 million of oil sales attributable to the assets acquired since the Llanos 2017 Acquisition. Revenue less direct costs for the period ended December 31, 2017 attributable to the assets acquired since the Llanos 2017 Acquisition is $0.9 million.

b) 2016 Llanos Basin additional working interest acquisition

On September 12, 2016, Parex acquired an additional 50% working interest in the El Eden Block and the Los Ocarros Block in Colombia's Llanos Basin (the "Llanos 2016 Acquisition"). The Company paid total net consideration of $4.0 million. The Llanos 2016 Acquisition increased the Company's working interest in both of the blocks to 100%.

The consolidated statement of comprehensive income (loss) includes results of operation of the Llanos 2016 Acquisition since the closing date of September 12, 2016. There were no transaction costs associated with the Llanos Acquisition.

This transaction has been accounted for using the acquisition method whereby the assets acquired and the liabilities assumed are recorded at fair values. As the fair value of the identifiable assets was determined to equal the purchase price, no goodwill arose on the transaction. The following table summarizes the recognizable assets acquired and consideration paid pursuant to the acquisition:

Assets acquired and liabilities assumed		
PP&E	$	6,561
Decommissioning and environmental liabilities		(2,536)
	$	**4,025**

Consideration for the acquisition		
Cash paid	$	4,025
Total net consideration paid	**$**	**4,025**

The pro forma results for the year ended December 31, 2016 are shown below, as if the Llanos 2016 Acquisition had occurred on January 1, 2016. Pro forma results are not indicative of actual results or future performance.

Oil sales	$	9,539
Net income	$	810
Basic net income per share	$	0.01
Diluted net income per share	$	0.01

The consolidated statement of comprehensive income (loss) for the year ended December 31, 2016 includes $3.7 million of oil sales attributable to the assets acquired since the Llanos 2016 Acquisition. Revenue less direct costs for the period ended December 31, 2016 attributable to the assets acquired since the Llanos 2016 Acquisition is $0.8 million.

Non-cash Impairment Charges

	For the three months ended December 31,		For the year ended December 31,	
($000s)	**2017**	2016	**2017**	2016
Impairment of E&E assets	**$ 35,621**	$ 69,880	**$ 35,621**	$ 69,880
Impairment of PP&E related to Block LLA-30 Llanos CGU	**—**	9,597	**—**	9,597
Total non-cash impairment charges before deferred income tax recoveries	**$ 35,621**	$ 79,477	**$ 35,621**	$ 79,477

An impairment of $35.6 million was recorded in the consolidated statement of comprehensive income (loss) for the three month period and year ended December 31, 2017 (three months and year ended December 31, 2016- $79.5 million)

The impairment of E&E assets of $35.6 million consisting of seismic and drilling costs in the three months and year ended December 31, 2017 was a result of the unsuccessful drilling of commitment wells on the Company's VMM-11 block primarily in the fourth quarter of 2017. The net book value of costs on these blocks has been impaired to $nil.

At December 31, 2017 Parex tested its CGU's for PP&E impairment where it was determined that the recoverable amount of the CGU's exceeded its carrying amount, and therefore the Company's CGU's were not impaired. The recoverable amount was determined using fair value less costs of disposal. Future cash flows were discounted using an after tax rate of 11 percent with the following prices being used by Parex' independent reserve evaluator at December 31, 2017:

	2018	2019	2020	2021	2022	Thereafter
Brent ($US/bbl)	65.50	63.50	63.00	66.00	69.00	2% increase per year

The impairment of E&E assets in 2016 was a result of the Company transferring drilling commitments on blocks LLA-24, Cebucan and Cerrero to other more prospective blocks. The transfer was approved in the first quarter of 2017 and these blocks were formally relinquished in 2017. The net book value of these blocks was impaired to $nil.

The impairment of PP&E in the three months and year ended December 31, 2016 was a result of a negative technical revision noted in the Company's December 31, 2016 reserve report on the Block LLA-30 CGU. The Company determined that the carrying amount of the CGU exceeded its recoverable amount. The recoverable amount was determined using fair value less costs of disposal. There are no E&E assets associated with this CGU. Future cash flows were discounted using an after tax rate of 11 percent. At December 31, 2016, the recoverable amount of the CGU was estimated to be $7.6 million.

The fair value for the producing properties in this CGU was calculated based on discounted after-tax cash flows of proved and probable reserves using forecast prices and cost estimates, consistent with the Company's independent qualified reserves evaluators. This approach requires assumptions about revenue, future oil prices, tax rates and discount rates, all of which are level 3 inputs.

Prices used by Parex' independent reserve evaluator at December 31, 2016 were as follows:

	2017	2018	2019	2020	2021	Thereafter
Brent ($US/bbl)	57.00	61.00	66.00	70.00	74.00	2% increase per year

For further information regarding the impairment charges for the years ended December 31, 2017 and 2016, refer to Note 7 "Exploration and Evaluation Assets" and Note 8 "Property, Plant and Equipment" in the audited consolidated financial statements.

Impairment Test of Goodwill

The Company performed its annual test for goodwill impairment at the balance sheet date in accordance with its policy described in note 3 of the audited consolidated financial statements for the years ended December 31, 2017 and 2016. The Company has allocated goodwill to the Colombia operating segment. The estimated fair value less costs of disposal of the Colombia operating segment exceeded the carrying value. As a result, no goodwill impairment was recorded. For additional information refer to Note 10 "Goodwill" in the audited consolidated financial statements.

Summary of Quarterly Results

Three months ended ($000s)		**Dec. 31, 2017**		Sep. 30, 2017		June 30, 2017		March 31, 2017
Average daily oil and natural gas production (boe/d)		**39,007**		36,195		34,291		32,591
Realized sales price ($/boe)		**56.90**		48.07		46.84		48.72
Financial (000s except per share amounts)								
Oil and natural gas sales	**$**	**203,930**	$	159,929	$	145,406	$	150,142
Funds flow from operations	**$**	**93,861**	$	65,998	$	51,763	$	67,906
Per share – basic		**0.61**		0.43		0.34		0.44
Per share – adjusted diluted(1)		**0.59**		0.42		0.33		0.43
Net (loss) income	**$**	**55,921**	$	55,527	$	3,524	$	40,106
Per share – basic		**0.36**		0.36		0.02		0.26
Per share – diluted		**0.36**		0.35		0.02		0.26
Capital Expenditures, excluding corporate acquisitions	**$**	**66,341**	$	51,434	$	59,008	$	35,563
Total assets (end of period)	**$**	**1,121,908**	$	1,057,859	$	1,015,540	$	984,855
Working capital surplus (end of period) (2)	**$**	**163,401**	$	140,292	$	128,347	$	131,056

(1) Non-GAAP term. See "Non-GAAP Terms" below.

(2) Working capital does not include the undrawn amount available on the credit facility.

Three months ended ($000s)		Dec. 31, 2016		Sep. 30, 2016		June 30, 2016		March 31, 2016
Average daily oil and natural gas production (boe/d)		31,049		29,754		29,136		28,900
Realized sales price ($/boe)		44.84		40.19		39.74		27.10
Financial (000s except per share amounts)								
Oil and natural gas sales	$	131,858	$	127,541	$	104,571	$	81,518
Funds flow from continuing operations	$	51,791	$	45,091	$	31,792	$	15,457
Per share – basic		0.34		0.30		0.21		0.10
Per share – adjusted diluted(1)		0.33		0.29		0.20		0.10
Net (loss) income	$	(45,440)	$	6,811	$	(185)	$	(7,630)
Per share – basic		(0.30)		0.04		0.00		(0.05)
Per share – diluted		(0.30)		0.04		0.00		(0.05)
Capital Expenditures, excluding corporate acquisitions	$	66,890	$	26,313	$	13,922	$	4,507
Total assets (end of period)	$	918,671	$	947,354	$	921,665	$	943,675
Working capital surplus (end of period) (2)	$	93,290	$	117,747	$	97,532	$	79,955

(1) Non-GAAP term. See "Non-GAAP Terms" below.

(2) Working capital does not include the undrawn amount available on the credit facility.

Factors that Caused Variations Quarter Over Quarter

During the fourth quarter of 2017, production of 39,007 boe/d was in excess of production compared to the previous quarter ended September 30, 2017. Revenue was higher than the previous quarter due to a increased sales volumes and a significant increase in world oil prices in the period. Funds flow from operations was higher than the previous quarter also due to increased sales volumes and realized sales prices per barrel. Capital expenditures for the fourth quarter of 2017 were $66.3 million compared to $51.4 million in the prior quarter mainly related to drilling on Block LLA-34, Cabrestero Block, and Capachos Block.

During the third quarter of 2017, production of 36,195 boe/d was in excess of production for the previous quarter ended June 30, 2017. Revenue was higher than the previous quarter due to a increased sales volumes and an increase in world oil prices in the period. Funds flow from operations was higher than the previous quarter also due to increased sales volumes and realized sales prices per barrel and due to a one-time payment in the previous quarter related to a legal settlement. Capital expenditures for the third quarter of 2017 were $51.4 million compared to $59.0 million in the prior quarter mainly related to drilling on Block LLA-34, Cabrestero Block, Capachos Block and Aguas Blancas field. Net income in the period increased largely due to a recovery in deferred tax in the amount of $29.9 million.

During the second quarter of 2017, production of 34,291 boe/d was in excess of production for the previous quarter ended March 31, 2017. Revenue was slightly lower than the previous quarter mainly due to a decrease in world oil prices in the period. Funds flow from operations was lower than the previous quarter due to a one-time payment of $15.0 million related to a legal settlement. Adjusting for this one-time payment, funds flow increased to $66.8 million, which is slightly lower than the previous quarter. Working capital was $128.3 million compared to $131.1 million at March 31, 2017. Capital expenditures for the second quarter of 2017 were $59.0 million compared $35.6 million in the prior quarter mainly related to drilling on Block LLA-34, Cabrestero Block, and Aguas Blancas field.

During the first quarter of 2017, production of 32,591 boe/d was in excess of oil production for the previous quarter ended December 31, 2016. Revenue and funds flow from operations were higher than the previous quarter mainly due to an increase in realized sales prices per barrel. Working capital has increased to $131.1 million from $93.3 million at December 31, 2016 mainly due to funds flow provided by operating activities of $67.9 million being in excess of capital expenditures of $35.6 million.

In Q4 2016, production was 31,049 boe/d, an increase of 4 percent over the previous quarter ended September 30, 2016. Working capital decreased to $93.3 million from $117.7 million at September 30, 2016. This was due to capital expenditures of $66.9 million for the fourth quarter of 2016 being in excess of funds flows provided by operations of $51.8 million; and an accrual for the 2017 current portion of asset retirement and environmental obligations in the amount of $10.9 million. Capital expenditures increased significantly in the fourth quarter compared to the third quarter of 2016 as the company drilled 10 wells (6.35 net) in Q4, 2016 compared to 4 gross (2.65 net) wells during Q3, 2016.

Please refer to "Financial and Operating Results" for detailed discussions on variations during the comparative quarters and to Parex' previously issued annual and interim MD&As for further information regarding changes in prior quarters.

Fourth Quarter Results

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

($000s) For the three month period ended December 31,		**2017**		2016
Oil and gas sales	**$**	**203,930**	$	131,858
Royalties		**(19,852)**		(10,360)
Revenue		**184,078**		121,498
Risk management contracts (loss)		**(1,324)**		(1,385)
		182,754		120,113
Expenses				
Production		**19,226**		15,364
Transportation		**37,694**		31,488
Purchased oil		**1,425**		4,170
General and administrative		**9,007**		6,961
Equity settled share-based compensation		**3,744**		3,807
Cash settled share-based compensation		**4,716**		1,401
Depletion, depreciation and amortization		**19,668**		23,133
Foreign exchange loss		**256**		1,769
Impairment of exploration and evaluation assets		**35,621**		69,880
Impairment of property, plant and equipment		**—**		9,597
		131,357		167,570
Finance (income)		**(5,871)**		(298)
Finance expense		**3,072**		4,477
Net finance expense		**(2,799)**		4,179
Income (loss) before income taxes		**54,196**		(51,636)
Income tax (recovery)				
Current tax expense		**15,492**		3,971
Deferred tax (recovery)		**(17,217)**		(10,167)
		(1,725)		(6,196)
Net income (loss) and comprehensive income (loss) for the period	**$**	**55,921**	$	(45,440)

Liquidity and Capital Resources

As at December 31, 2017 the Company had a working capital surplus of $163.4 million, excluding amounts available under the credit facility, as compared to working capital surplus of $93.3 million at December 31, 2016. Bank debt was $nil at December 31, 2017 and December 31, 2016. The credit facility has a current borrowing base of $100.0 million and is subject to a borrowing base redetermination to be completed by the end of May, 2018. At December 31, 2017 Parex held $235.0 million of cash, compared to $195.9 million at September 30, 2017 and $149.2 million at December 31, 2016. The Company's cash balances reside primarily in current accounts with chartered financial instutions, the majority of which are held on account in Canada and Barbados in USD. The increase in the Company's cash and working capital positions from prior periods is a result of the Company generating free cash flow for the year ended December 31, 2017.

Parex' senior secured credit facility ("credit facility") with a syndicate of banks has a current borrowing base of $100.0 million. Key covenants include a rolling four quarters total funded debt to adjusted EBITDA test of 3:50:1, and other standard business operating covenants. Given there is $nil balance drawn on the facility as at December 31, 2017, the Company is in compliance with all covenants. The next annual review is scheduled to occur at the end of May 2018. Parex voluntarily reduced the borrowing base on the credit facility to $100.0 million from $175.0 million at the semi-annual review in May 2017. This was done to reduce costs associated with the credit facility. As the Company currently has $nil bank debt and no plans in 2018 to utilize the credit facility, the next re-determination is not expected to impact the Company's current or future operations or reduce the 2018 outlook.

In the fourth quarter of 2017 the Company put in place an automatic share purchase plan with a broker in order to facilitate repurchases of up to 3.0 million of its common shares. Under the Company's automatic share purchase plan, the Company's broker may repurchase shares under the normal course issuer bid during the Company's self-imposed blackout periods. The repurchase plan is seen by management as a way to support shareholders, reduce dilution of common shares when stock based share exercises occur, and provide additional liquidity to holders of common shares.

Refer to note 23 - Commitments and Contingencies of the audited financial statements for the year ended December 31, 2017 for a description of the performance guarantee facility with EDC as well as the unsecured letters of credit.

Outstanding Share Data

Parex is authorized to issue an unlimited number of voting common shares without nominal or par value. As at December 31, 2017 the Company had 154,742,134 common shares outstanding.

The Company has a stock option and RSU (which includes PSUs) plan. The plans provide for the issuance of stock options, RSUs and PSUs to the Company's officers, executive and certain employees to acquire common shares. The maximum number of stock options, RSUs and PSUs reserved for issuance under the two plans may not exceed 10 percent of the number of common shares issued and outstanding. RSU's (which includes PSUs) reserved for issuance may not exceed 4 percent of the common shares issued and outstanding.

As at March 5, 2018 Parex has the following securities outstanding:

	Number	%
Common shares	155,020,803	94%
Stock options	6,218,452	4%
Restricted and performance share units	3,486,739	2%
	164,725,994	100%

As of the date of this MD&A, total stock options, RSUs and PSUs outstanding represent approximately 6 percent of the total issued and outstanding common shares.

Contractual Obligations, Commitments and Guarantees

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

In Colombia, the Company has provided guarantees to the ANH and Ecopetrol which on December 31, 2017 were $142.6 million (December 31, 2016 - $148.7 million) to support the exploration work commitments on its blocks. The guarantees have been provided in the form of letters of credit for varying terms. Export Development Canada ("EDC") has provided performance security guarantees under the Company's $250.0 million (December 31, 2016 - $200.0 million) performance guarantee facility to support approximately $116.1 million (December 31, 2016 - $126.4 million) of the letters of credit issued on behalf of Parex. The letters of credit issued to the ANH are reduced from time to time to reflect the work performed on the various blocks.

The following table summarizes the Company's estimated commitments as at December 31, 2017:

($000s)	Total	<1 year	1 – 3 years	3 – 4 years	>5 years
Exploration	$ 161,979	$ 57,541	$ 104,438	$ —	$ —
Office and accommodations[1]	7,202	1,684	2,222	1,727	1,569
Decommissioning expenditures	85,420	9,768	—	—	75,652
Total	$ 254,601	$ 68,993	$ 106,660	$ 1,727	$ 77,221

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

Decommissioning and Environmental Liabilities

	Decommissioning	Environmental	Total
Balance, December 31, 2015	$ 26,811	$ 8,588	$ 35,399
Additions	5,241	703	5,944
Settlements of obligations during the year	(75)	(103)	(178)
Accretion expense	1,432	399	1,831
Additions related to change in estimate - inflation and discount rates	7,697	1,482	9,179
Additions related to change in estimate - costs	(2,386)	1,677	(709)
Foreign exchange (gain)	—	(320)	(320)
Balance, December 31, 2016	$ 38,720	$ 12,426	$ 51,146
Additions	5,313	2,223	7,536
Settlements of obligations during the year	(954)	(437)	(1,391)
Accretion expense	2,549	1,416	3,965
Additions related to change in estimate - inflation and discount rates	(9,773)	(1,809)	(11,582)
Additions related to change in estimate - costs	391	2,499	2,890
Foreign exchange (gain) loss	528	(412)	116
Balance, December 31, 2017	**36,774**	**15,906**	**52,680**
Current obligation	(4,159)	(5,609)	(9,768)
Long-term obligation	**$ 32,615**	**$ 10,297**	**$ 42,912**

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

The total decommissioning and environmental liability is estimated based on the Company's net ownership in wells drilled as at December 31, 2017, the estimated costs to abandon and reclaim the wells and well sites and the estimated timing of the costs to be paid in future periods. The total undiscounted amount of cash flows required to settle the Company's decommissioning liability is approximately $66.4 million as at December 31, 2017 (December 31, 2016 – $92.1 million) with the majority of these costs anticipated to occur in 2021 or later. A risk-free discount rate of 7.5 percent and an inflation rate of 4.0 percent were used in the valuation of the liabilities (December 31, 2016 – 7.2 percent risk-free discount rate and a 7.5 percent inflation rate). The risk-free discount rate and the inflation rate used in 2017 are based on forecast Colombia rates.

Included in the decommissioning liability is $4.2 million (December 31, 2016 – $4.2 million) that is classified as a current obligation.

The total undiscounted amount of cash flows required to settle the Company's environmental liability is approximately $19.0 million as at December 31, 2017 (December 31, 2016 – $16.1 million) with the majority of these costs anticipated to occur in 2018 or later in Colombia. A risk-free discount rate of 7.5 percent and an inflation rate of 4.0 percent were used in the valuation of the liabilities (December 31, 2016 – 7.2 percent risk-free discount rate and a 7.5 percent inflation rate). The risk-free discount rate and the inflation rate used in 2017 are based on forecast Colombia rates.

Included in the environmental liability is $5.6 million (December 31, 2016 –$6.7 million) that is classified as a current obligation.

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

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

Reserves Information

The reserves information summarized in this MD&A is from reports prepared by our independent reserves evaluator, GLJ Petroleum Consultants Ltd. ("GLJ"), dated February 3, 2018 with an effective date of December 31, 2017, and dated February 3, 2017 with an effective date of December 31, 2016. Each of these reports was prepared in accordance with definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook ("COGE") and National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). All December 31, 2017 reserves presented are based on GLJ's forecast pricing effective January 1, 2018 and all December 31, 2016 reserves presented are based on GLJ's forecast pricing effective January 1, 2017. Additional reserve information for December 31, 2017 as required under NI 51-101 will be included in the Company's Annual Information Form which will be filed on SEDAR by March 30, 2018. Additional information in respect of our December 31, 2016 reserves is contained in the AIF.

This MD&A contains certain oil and gas metrics, including finding, development and acquisition ("FD&A") costs, reserves replacement and reserves additions, which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included herein to provide readers with additional measures to evaluate the Company's performance; however, such measures are not reliable indicators of the future performance of the Company and future performance may not compare to the performance in previous periods and therefore such metrics should not be unduly relied upon.

FD&A is the sum of total capital expenditures incurred in the period and the change in future development capital ("FDC") required to develop reserves. FD&A cost per bbl is determined by dividing current period net reserve additions into the corresponding period's FD&A cost. Total capital includes both capital expenditures incurred and changes in future development capital required to bring proved undeveloped reserves and probable reserves to production during the applicable period. Reserve additions are calculated as the change in reserves from the beginning to the end of the applicable period excluding production. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated FD&A generally will not reflect total finding and development costs related to reserves additions for that year. Changes in forecast FD&A occur annually as a result of development activities, acquisition and disposition activities and capital cost estimates that reflect our independent reserve evaluator's best estimate of what it will cost to bring the proved undeveloped and probable reserves on production.

Reserves replacement is calculated as 63.3 million barrels of oil equivalent gross proved plus probable reserve additions (including acquisitions) during the year ended December 31, 2017 divided by current annual production of 35,541 barrels per day and expressed as a percentage. Reserve additions is calculated as the change in proved plus probable reserves from December 31, 2016 (111.904 million barrels of oil equivalent (net company working interest)) to December 31, 2017 (162.236 million barrels of oil equivalent (net company working interest)) excluding production of approximately 13.0 million barrels of oil equivalent (net company working interest).

Advisory on Forward-Looking Statements

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

- the Company's operational strategy and focus, including targeted jurisdictions and technologies used to execute its strategy;
- the Company's approach to manage subsurface and commercial risks;
- the Company's exploration blocks subject to farm-in and earning requirements and the effect on the Company's land holdings as lands deemed non-commercial are released;
- activities to be undertaken in various areas including the fulfillment of exploration commitments and farm-in obligations;
- terms of exploration and production contracts and the timing of release of exploration property deemed non-commercial in respect of the exploration contracts;
- the Company's capital program budget for 2018, including the expected allocation of such expenditures and the Company's plans to fund its 2018 capital program from funds flow from operations;
- the expected budgeted per boe discount to Brent for 2018;
- the calculation and applicability of the HPR;
- the Company's expectations regarding the per boe impact caused by appreciation and depreciation of the Colombian peso;
- the effect of the Colombian peso/US$ exchange rate on the variability of transportation costs and production costs;
- terms and cost of share-based compensation plans, including stock option plan, restricted share unit (including preferred share units) plan, deferred share unit plan, share appreciation rights and cash settled restricted share unit plan;
- foreign currency risk and the ability to reverse unrealized foreign exchange gains and losses in the future;
- the Company's risk management strategy and the use of derivatives primarily with financial institutions to manage movements in the price of crude oil, fluctuations in the US/COP exchange rate and interest rate movements;
- terms of the Company's risk management contracts and the Company's ability to manage and forecast cash flow;
- the Company's estimated effective current tax rate for 2018;
- the Company's estimated current tax expense for 2018;
- terms of the Company's credit facility including the timing of the next borrowing base redetermination;
- the Company's expectation that the next redetermination of it's credit facility will not impact its current or future operations or reduce the 2018 outlook;
- benefits derived from the normal course issuer bid and the automatic share purchase plan;
- estimated amounts, timing and the anticipated sources of funding for the Company's environmental, decommissioning and restoration obligations; and
- effect of environmental initiatives in Colombia and business and environmental risks on the Company.

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

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

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

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

This MD&A may contain future oriented financial information ("FOFI") within the meaning of applicable securities laws. The FOFI has been prepared by management to provide an outlook of the Company's activities and results and may not be appropriate for other purposes. The FOFI has been prepared based on a number of assumptions including the assumptions discussed above. The actual results of operations of the Company and the resulting financial results may vary from the amounts set forth herein, and such variations may be material. The Company and management believe that the FOFI has been prepared on a reasonable basis, reflecting management's best estimates and judgments. FOFI contained in this MD&A was made as of the date of this MD&A and the Company disclaims any intention or obligations to update or revise any FOFI contained in this MD&A, whether as a result of new information, future events or otherwise, unless required pursuant to applicable law.

Non-GAAP Terms

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

Diluted funds flow per share *is calculated by dividing funds flow provided by operations by the weighted average number of shares outstanding. Parex presents adjusted funds flow provided by operations per share whereby per share amounts are calculated using weighted-average shares outstanding, consistent with the calculation of earnings per share. The following table shows the variables used in the calculation of diluted funds flow per share:*

($000s)	For the three months ended December 31, 2017	2016	For the year ended December 31, 2017	2016
Funds flow provided by operations	**$ 93,861**	$ 51,791	**$ 279,528**	$ 144,131
Weighted average number of shares for the purposes of basic funds flow ($000s)	**154,812**	152,778	**154,209**	152,184
Dilutive effect of share options on potential common shares	**3,928**	3,064	**3,063**	2,234
Weighted average number of shares for the purposes of diluted funds flow	**158,740**	155,842	**157,272**	154,418

Adjusted EBITDA *is defined as net income (loss) before interest, taxes, depletion and depreciation and adjusted for other non-cash items, transaction costs and extraordinary and non-recurring items. Adjusted EBITDA is solely used in the calculation of the bank covenant and is not considered a key performance measure by Management.*

Operating netback per boe

The Company considers operating netbacks to be a key measure as they demonstrate Parex' profitability relative to current commodity prices. Below is a description of each component of the Company's operating netback and how it is determined:

Oil and natural gas sales per boe *is determined by sales revenue excluding risk management contracts less non-cash oil revenue from overlifted Ocensa pipeline volumes divided by total equivalent sales volume including purchased oil volumes. A reconciliation of the calculation of oil and natural gas sales per boe is provided below:*

($000s)	For the three months ended December 31, 2017	2016	For the year ended December 31, 2017	2016
Oil and natural gas revenue excluding risk management contracts	**$ 203,930**	$ 131,859	**$ 659,407**	$ 445,488
Non-cash oil revenue from overlifted Ocensa pipeline volumes	**—**	(20,014)	**—**	(20,014)
Oil revenue for purposes of sales price per boe	**$ 203,930**	$ 111,845	**$ 659,407**	$ 425,474
Denominator (BOEs)				
Company produced oil and natural gas sales in period	**3,556,444**	2,428,306	**12,961,150**	10,919,610
Purchased oil volumes sold	**27,645**	65,813	**135,780**	387,594
Total oil and natural gas sales volumes	**3,584,089**	2,494,119	**13,096,930**	11,307,204
Sales price per boe	**$ 56.90**	$ 44.84	**$ 50.35**	$ 37.63

Royalties per boe *is determined by dividing royalty expense by the total equivalent sales volume plus overlifted Ocensa volumes returned in the period and excludes purchased oil volumes. A reconciliation of royalties per boe is provided below:*

($000s)	For the three months ended December 31, 2017	2016	For the year ended December 31, 2017	2016
Royalty expense	**$ 19,852**	$ 10,360	**$ 58,540**	$ 34,327
Denominator (BOEs)				
Company produced oil and natural gas sales in period	**3,556,444**	2,428,306	**12,961,150**	10,919,610
Overlifted oil volumes returned to Ocensa pipeline	**—**	335,772	**—**	—
Total oil and natural gas sales volumes	**3,556,444**	2,764,078	**12,961,150**	10,919,610
Royalty expense per boe	**$ 5.58**	$ 3.75	**$ 4.52**	$ 3.14

***Production expense per boe** is determined by dividing production expense by the total equivalent sales volume plus overlifted Ocensa volumes returned in the period and excludes purchased oil volumes. A reconciliation of production expense per boe is provided below:*

	For the three months ended December 31,		For the year ended December 31,	
($000s)	**2017**	2016	**2017**	2016
Production Expense	**$ 19,226**	$ 15,364	**$ 69,169**	$ 53,250
Denominator (BOEs)				
Company produced oil and natural gas sales in period	**3,556,444**	2,428,306	**12,961,150**	10,919,610
Overlifted oil volumes returned to Ocensa pipeline	**—**	335,772	**—**	—
Total oil and natural gas sales volumes	**3,556,444**	2,764,078	**12,961,150**	10,919,610
Production expense per boe	**$ 5.41**	$ 5.56	**$ 5.34**	$ 4.88

***Transportation expense per boe** is determined by dividing the transportation expense by the total equivalent sales volumes including purchased oil volumes plus overlifted Ocensa volumes returned in the period. A reconciliation of transportation expense per boe is provided below:*

	For the three months ended December 31,		For the year ended December 31,	
($000s)	**2017**	2016	**2017**	2016
Transportation Expense	**$ 37,694**	$ 31,488	**$ 141,475**	$ 130,929
Denominator (BOEs)				
Company produced oil and natural gas sales in period	**3,556,444**	2,428,306	**12,961,150**	10,919,610
Overlifted oil volumes returned to Ocensa pipeline	**—**	335,772	**—**	—
Purchased oil volumes sold	**27,645**	65,813	**135,780**	387,594
Total oil and natural gas sales volumes	**3,584,089**	2,829,891	**13,096,930**	11,307,204
Transportation expense per boe	**$ 10.52**	$ 11.13	**$ 10.80**	$ 11.58

***Free funds flow (deficiency)** is determined by funds flow from continuing operations less capital expenditures as follows:*

	For the three months ended December 31,		For the year ended December 31,	
($000s)	**2017**	2016	**2017**	2016
Funds flow provided by operations	**$ 93,861**	$ 51,791	**$ 279,528**	$ 144,131
Capital expenditures, excluding corporate acquisitions	**$ 66,341**	66,980	**$ 212,346**	111,722
Free funds flow (deficiency)	**$ 27,520**	$ (15,189)	**$ 67,182**	$ 32,409

Environmental Initiatives Impacting Parex

In Colombia there is currently no specific regulation that obliges companies to specifically monitor and report greenhouse gas emissions. However in 2017 the Colombian government submitted a bill which sets guidelines to manage climate change, although very little specifics were given. Although at the present time there is no specific regulations related to climate change or greenhouse gas emissions Parex has a plan in place to monitor and disclose key metrics surrounding the environmental impacts of Parex' operations. Climate change regulation in Colombia has the potential to significantly affect the regulatory environment of the crude oil and natural gas industry in Colombia. Such regulations impose certain costs and risks on the industry, and there remains some uncertainty with regard to the impacts of climate change and environmental laws and regulations, as Parex is unable to predict additional legislation or amendments that the Colombian government may enact in the future. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact on the Company's operations and cash flow.

Business Environment and Risks

Overall

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

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

Foreign Jurisdiction Political Risk

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

In 2018 there will be national elections in Colombia which will result in a new country president who may take positions on oil and gas policy issues that are contrary to the Company's interests. Any changes in the ruling government, oil and gas or investment regulations and policies or a shift in political attitudes in Colombia in which the Company operates are beyond its control and may significantly reduce its ability to expand its operations or operate a profitable business.

Security in Colombia

A 50-year armed conflict between government forces and anti-government insurgent groups and illegal paramilitary groups, both thought to be funded by the drug trade, continues in Colombia. Insurgents continue to attack civilians and violent guerrilla activity continues in certain parts of the country. Regions that border Venezuela and Ecuador have historically been areas of high security risk and there continues to be guerrilla activity.

Recently in February 2018, after the Ejército de Liberación Nacional ("ELN") cease-fire expired, the Company suspended operations at the Capachos field which is in an area of strong ELN presence. With the support of local communities and federal authorities the Company has resumed operations. This is the first time operations have been suspended for security concerns in the Company's nine year history.

Continuing attempts to reduce or prevent guerrilla activity may not be successful and guerrilla activity may disrupt Parex Colombia operations in the future. The Company may not be able to establish or maintain the safety of its operations and personnel in Colombia and this violence may affect its operations in the future. Continued or heightened security concerns in Colombia could also result in a significant loss to Parex and/or costs exceeding current expectations.

Reserves Estimates

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

Volatility of Commodity Prices and Foreign Exchange Rates

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

Foreign currency risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate as a result of changes in foreign currency exchange rates. The Company is exposed to foreign currency fluctuations as various portions of its cash balances and future expenses and revenues are denominated in Colombian pesos (COP$) and Canadian dollars (Cdn$).

Counterparty Risk

Credit risk is the risk of a counterparty failing to meet its obligations in accordance with the agreed upon terms. The Company may be exposed to third-party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its commodities and other parties. Parex has established credit policies and controls designed to mitigate the risk of default or non-payment with respect to oil and natural gas sales, financial hedging transactions and joint venture participants. The Company makes every effort to sell its commodities to major companies with excellent credit ratings and/or managing its crude production on a portfolio basis.

Access to Capital

From time to time, the Company may have to raise additional funds to finance business development activities. Parex' ability to raise additional capital will depend on a number of factors such as general economic and market conditions that are beyond the Company's control. Internally generated funds will also fluctuate with changing commodity prices. Parex currently has a $100 million syndicated facility with three banks. The Company is required to comply with covenants under this facility and in the event it does not comply, access to capital could be restricted or repayment may be required. Parex routinely reviews the covenants based on actual and forecasted results and has the ability to make changes to development and exploration plans to comply with the covenants under the credit facility. Parex is committed to maintaining a strong balance sheet along with an adaptable capital expenditure program that can be adjusted to capitalize on, or reflect acquisition opportunities and, if necessary a tightening of liquidity sources. From the company's founding to the date of this MD&A, Parex has had no defaults or breaches on its bank debt or any of its financial liabilities.

Operational Matters

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

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

Exploration

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

Cyber-Security

The Company is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Company's information technology systems by third parties or insiders. Although the Company has security measures and controls in place that are designed to mitigate these risks, a breach of its security measures and/or a loss of information could occur and result in a loss of material and confidential information and reputation, breach of privacy laws and a disruption to its business activities. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on the Company's business, financial condition and results of operations. Parex relies on information technology, such as computer hardware and software systems, in order to properly operate its business. In the event the Company is unable to regularly deploy software and hardware, effectively upgrade systems and network infrastructure, and take other steps to maintain or improve the efficiency and efficacy of systems, the operation of such systems could be interrupted or result in the loss, corruption, or release of data. In addition, information systems could be damaged or interrupted by natural disasters, force majeure events, telecommunications failures, power loss, acts of war or terrorism, computer viruses, malicious code, physical or electronic security breaches, intentional or inadvertent user misuse or error, or similar events or disruptions. Any of these or other events could cause interruptions, delays, loss of critical or sensitive data or similar effects, which could have a material adverse impact on the protection of intellectual property, and confidential and proprietary information, and on Parex' business, financial condition, results of operations and funds flow from operations.

Internal Controls over Financial Reporting

Disclosure controls and procedures ("DC&P"), as defined in National Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*, are designed to provide reasonable assurance that information required to be disclosed in annual filings, interim filings or other reports filed, or submitted by the Company under securities legislation authorities is recorded, processed, summarized and reported within the time periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the Company's management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. The Chief Executive Officer and the Chief Financial Officer of Parex evaluated the effectiveness of the design and operation of the Company's DC&P. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded Parex DC&P were effective as at December 31, 2017.

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

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

The Chief Executive Officer and the Chief Financial Officer are responsible for establishing and maintaining ICFR for Parex. They have, as at the financial year ended December 31, 2017, designed ICFR, or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The control framework Parex officers used to design the Company's ICFR is the 2013 Internal Control - Integrated Framework ("COSO Framework") published by The Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Under the supervision of the Chief Executive Officer and the Chief Financial Officer, Parex conducted an evaluation of the effectiveness of the Company's ICFR as at December 31, 2017 based on the COSO Framework. Based on this evaluation, the officers concluded that as of December 31, 2017, Parex maintained effective ICFR. It should be noted that while Parex officers believe that the Company's controls provide a reasonable level of assurance with regard to their effectiveness, they do not expect that the DC&P and ICFR will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, but not absolute, assurance that the objectives of the control system are met.

There were no changes in Parex' ICFR during the year ended December 31, 2017 that materially affected, or are reasonably likely to materially affect, the Company's ICFR.

Off-Balance-Sheet Arrangements

The Company did not enter into any off-balance-sheet arrangements during the twelve months ended December 31, 2017.

Financial Instruments and Other Instruments

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

Related Party Transactions

Compensation of Key Management Personnel

Key management personnel compensation, including directors, is as follows:

		2017		2016
Salaries, directors fees and other benefits	**$**	**2,980**	$	2,432
Share-based compensation[(1)]		**7,430**		4,117
	$	**10,410**	$	6,549

(1) Non-cash share-based compensation expense for the year.

At December 31, 2017 key management personnel are comprised of the Company's directors and seven executives. As at December 31, 2017, there is a $8.2 million commitment relating to change of control or termination of employment of the seven executives (December 31, 2016 - $6.3 million for the five executives).

Other related party transactions
During the years ended December 31, 2017 and 2016, the Company rented office space to certain directors of the Company at market rental rates. The Company earned $17 thousand dollars during the year ended December 31, 2017 (year ended December 31, 2016 - $25 thousand dollars) in rental income from these related parties. The lease was terminated in September 2017 and at December 31, 2017 and 2016, $nil of this balance was outstanding.

Other than the above noted transaction, the Company did not have any related party transactions with entities outside the consolidated group for the years ended December 31, 2017 and 2016.

Accounting Policies and Estimates

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

a) Consolidation
The consolidated financial statements include the accounts of the Company and all of its subsidiaries at December 31, 2017. The principal operating subsidiaries and their activities are:

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

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

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

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

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

c) *Financial instruments*

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

Loans and receivables

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

Other financial liabilities

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

Derivative instruments

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

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

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

d) *Capital assets*

(i) Exploration and evaluation

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

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

(ii) Property, plant and equipment

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

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

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

e) Impairment of long-term assets

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

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

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

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

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in comprehensive income (loss).

The recoverable amount of goodwill is determined as the fair value less costs of disposal using a discounted cash flow method. Goodwill is evaluated at the Colombia segment level as business combinations giving rise to goodwill do not have specifically identifiable benefits to any one CGU.

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

f) Crude oil inventory and overlift oil volumes

Crude oil inventory consists of crude oil in transit at the balance sheet date and is valued at the lower of cost, using the weighted average cost method, and net realizable value. Costs include direct and indirect expenditures incurred in bringing the crude oil to its existing condition and location. The liability for overlift oil volumes is valued based on the Brent oil price at the balance sheet date. Sales revenue is subsequently recorded at the Brent oil price once the overlifted pipeline volumes are returned. A gain/loss on overlifted oil volumes is recorded on the difference between the original liability and the revenue recorded on the returned barrels.

g) Purchased oil

Purchased oil includes costs to buy third party oil and accruals for overlifted oil volumes. The costs for third party oil are initially recorded in inventory until the crude oil title is transferred. The costs for overlifted oil volumes are originally recorded as an accrued liability until the volumes are returned.

h) Goodwill

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

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

j) Equity settled share-based compensation
The Company has an incentive stock option plan and a restricted unit plan pursuant to which the Company may issue Restricted Share Units ("RSUs") and Performance Share Units ("PSUs") for certain employees, officers and directors as described in note 14. The Company records share-based compensation expense using the fair value method. The fair value of an option granted is calculated at the grant date using the Black-Scholes pricing model, and expensed over the vesting period of the option. The fair value of each RSU and PSU granted is calculated using the market price of Parex shares on the date of issuance, and expensed over the vesting period of the RSU and PSU. The Company determines an appropriate forfeiture rate by examining the history of its forfeitures. The Company records the cumulative share-based compensation as contributed surplus. When options, RSUs or PSUs are exercised, contributed surplus is reduced and share capital is increased by the amount of accumulated share-based compensation for the exercised security. Any consideration received on the exercise of stock options, RSUs or PSUs is credited to share capital.

PSUs may be granted with certain performance measures, specified at the grant date as determined by the Company's Board of Directors. Based upon the achievement of the performance measures, a pre-determined adjustment factor of between 0-2x is applied to PSUs eligible to vest at the end of the performance period. The expense recognized over the vesting period of PSUs is the fair value of the PSUs with an estimated adjustment factor. If the actual final adjustment factor is higher than estimated at grant, additional expense is recognized on vesting for the incremental fair value. Upon the exercise of the options, RSUs and PSUs consideration paid together with the amount previously recognized in contributed surplus is recorded as an increase to share capital.

k) Cash settled share-based compensation
The Company has a share appreciation rights plan for certain employees of Parex Colombia as described in note 15. Obligations for payments of cash under the foreign subsidiaries' SARs plan are accrued as compensation expense over the vesting period based on the fair value of SARs, subject to appreciation limits specified in the plan. The fair value of SARs is measured using the Black-Scholes pricing model. In accordance with the fair value method, increases or decreases in the fair value of the SARs result in a corresponding change in the recorded liability. The accrued compensation for a right that is forfeited is adjusted by decreasing compensation cost in the period of forfeiture.

The Company has a Cash Settled Restricted Share Unit ("CRSUs") plan which allows the Company to issue CRSUs to certain employees of Parex Colombia as described in note 15. Obligations for payments of cash under the foreign subsidiaries' CRSUs plan are accrued as compensation expense over the vesting period based on the fair value of CRSUs. The fair value of CRSUs is equal to the market price of the Company's common shares at the valuation date. In accordance with the fair value method, increases or decreases in the fair value of the CRSUs result in a corresponding change in the recorded liability. The accrued compensation for a right that is forfeited is adjusted by decreasing compensation cost in the period of forfeiture. The CRSUs liability cannot be settled by the issuance of common shares.

In the current year the Company amended the terms of its Deferred Share Unit ("DSU") plan which allows the Company to issue DSUs to certain non-employee directors of Parex Resources Inc, as described in note 15. Previously DSUs were settled in shares or cash at the discretion of the Company. Going forward the DSUs will be settled in cash and the DSUs liability cannot be settled by the issuance of common shares. As DSUs vest immediately on issuance, obligations for payments of cash under the DSUs plan are accrued as compensation expense immediately on issuance based on the fair value of the DSUs. The fair value of DSUs at each reporting period is equal to the market price of the Company's common shares at the valuation date. In accordance with the fair value method, increases or decreases in the fair value of the DSUs result in a corresponding change in the recorded liability. The accrued compensation for a unit that is forfeited is adjusted by decreasing compensation cost in the period of forfeiture.

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

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

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

n) Operating Segments

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

o) Finance income and expense

Finance expense comprises interest expense on borrowings, bank taxes, accretion on provisions, net wealth tax, impairment losses recognized on financial assets and gains/losses on overlifted oil volumes. Finance income comprises interest earned on cash and other income and gains on property acquisitions.

p) Cash

Cash is comprised of cash and other short-term highly liquid investments with maturities less than 3 months held in chartered banks in Canada and recognized financial institutions abroad with BBB+ credit ratings or higher.

q) Income taxes

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

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

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

r) Per share information

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

s) New standards and interpretations not yet adopted

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

IFRS 15 Revenue from Contracts with Customers - In April 2016, the IASB issued its final amendments to IFRS 15 Revenue from Contracts with Customers ("IFRS 15"), which replaces IAS 18 Revenue, IAS 11 Construction Contracts, and related interpretations. IFRS 15 provides a single, principles-based five-step model to be applied to all contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive when control is transferred to the purchaser. Disclosure requirements have also been expanded. The standard is required to be adopted either retrospectively or using a modified retrospective approach for annual periods beginning on or after January 1, 2018, with earlier adoption permitted.

The Company has reviewed its revenue streams and underlying contracts with customers. It has been concluded that the adoption of IFRS 15 will not have a material impact on the Company's net income and financial position. However, the Company will expand the disclosures in the notes to its financial statements as prescribed by IFRS 15, including disclosing the Company's disaggregated revenue streams by product type.

IFRS 9 Financial Instruments - In July 2014, the IASB completed the final elements of IFRS 9 Financial Instruments ("IFRS 9"). The standard supersedes earlier versions of IFRS 9 and completes the IASB's project to replace IAS 39 Financial Instruments: Recognition and Measurement ("IAS 39"). IFRS 9 introduces a single approach to determine whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. For financial liabilities, IFRS 9 retains most of the requirements of IAS 39; however, where the fair value option is applied to financial liabilities, any change in fair value resulting from an entity's own credit risk is recorded in other comprehensive income rather than the statement of income. The Company has determined that adoption of IFRS 9 will not result in changes to the classification of the Company's financial assets or the classification of the Company's financial liabilities. The Company has also determined there will not be any material changes in the measurement and carrying values of the Company's financial instruments as a result of the adoption of IFRS 9.

In addition, IFRS 9 introduces a new expected credit loss model for calculating impairment of financial assets, replacing the incurred loss impairment model required by IAS 39. The Company has determined that the new impairment model will not result in material changes to the valuation of its financial assets on adoption of IFRS 9. IFRS 9 also contains a new model to be applied for hedge accounting. The Company does not currently apply hedge accounting to its risk management contracts and does not currently intend to apply hedge accounting to any of its existing risk management contracts on adoption of IFRS 9. The standard will come into effect for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. IFRS 9, as well as consequential amendments to IFRS 7 Financial Instruments: Disclosures ("IFRS 7"), will be applied on a retrospective basis by the Company on January 1, 2018.

IFRS 16 Leases - In January 2016, the IASB issued IFRS 16 Leases ("IFRS 16"), which replaces IAS 17 Leases and IFRIC 4 Determining Whether an Arrangement Contains a Lease. IFRS 16 requires the recognition of lease assets and liabilities on the balance sheet for most leases, where the entity is acting as a lessee. For lessees applying IFRS 16, the dual classification model of leases as either operating leases or finance leases no longer exists, effectively treating all leases as finance leases. Certain short-term leases (less than 12 months) and leases of low-value assets are exempt from the balance sheet recognition requirements, and may continue to be treated as operating leases. Lessors will continue with the dual classification model for leases and the accounting for lessors remains virtually unchanged.

The standard will come into effect for annual periods beginning on or after January 1, 2019, with earlier adoption permitted if the entity is also applying IFRS 15. IFRS 16 is required to be adopted either retrospectively or using a modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect as an adjustment to opening retained earnings and applies the standard prospectively.

IFRS 16 will be applied by the Company on January 1, 2019. The Company is currently engaging and educating stakeholders and is implementing corporate processes to ensure contract completeness to identify leases. Identifying, gathering and analyzing contracts impacted by the adoption of the new standard will extend into 2018. Although the transition approach on adoption has not yet been determined, it is anticipated that the adoption of IFRS 16 will have a material impact on the Company's financial statements.

Critical Accounting Estimates

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

Oil and natural gas reserves

The Company retains qualified independent reserves evaluators to evaluate the Company's proved and probable oil and natural gas reserves. As at December 31, 2017 and in prior periods, Parex' reserves were evaluated by GLJ Petroleum Consultants Ltd., who are a firm of qualified independent reserves evaluators. The evaluation was conducted in accordance with the COGE handbook and NI 51-101. The Operations and Reserves Committee of the Company's Board of Directors is comprised of independent directors whose mandate is to steward the reserves evaluation process.

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

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

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

Decommissioning and environmental liabilities

The Company is required to recognize a liability for future dismantling, decommissioning, environmental, abandoning and site disturbance remediation costs associated with the Company's oil and natural gas properties in accordance with existing laws, contracts or other policies. The fair value of the estimated decommissioning and environmental liability is recorded as a long-term liability, with a corresponding increase in the carrying amount of the related long-lived asset, which is depleted on a unit-of-production basis over the life of the reserves. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to net income (loss), and for revisions to the estimated future cash flows. Actual costs incurred upon settlement of the obligations are charged against the liability.

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

Current and Deferred tax

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

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

Share-based compensation

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

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

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

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

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

In accordance with the fair value method, increases or decreases in the fair value of the CRSUs result in a corresponding change in the recorded liability. The accrued compensation for a right that is forfeited is adjusted by decreasing compensation cost in the period of forfeiture.

PSUs may be granted with certain performance measures, specified at the grant date as determined by the Company's Board of Directors. Based upon the achievement of the performance measures, a pre-determined adjustment factor of between 0-2x is applied to PSUs eligible to vest at the end of the performance period. The expense recognized over the vesting period of PSUs is the fair value of the PSUs with an estimated adjustment factor.

The fair value of a DSU is calculated using the market price of Parex shares on the date of issuance, and expensed immediately. In accordance with the fair value method, increases or decreases in the fair value of the DSUs result in a corresponding change in the recorded liability. The accrued compensation for a right that is forfeited is adjusted by decreasing compensation cost in the period of forfeiture.

Goodwill

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

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

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

Derivative liabilities

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

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

Legal, environmental remediation and other contingent matters

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

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OFFICERS & SENIOR EXECUTIVES

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President and Chief Executive Officer

Kenneth G. Pinsky
Chief Financial Officer & Corporate Secretary

Stu R. Davie
Vice President Corporate Services

Lee DiStefano
President, Parex Colombia & Country Manager

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ABBREVIATIONS

Oil and Natural Gas Liquids

bbls	barrels
mbbls	one thousand barrels
mmbbls	one million barrels
NGLs	natural gas liquids
bbls/d	barrels of oil per day
mbbls/d	one thousand barrels per day
BOE or boe	barrel of oil equivalent, using the conversion factor of 6 Mcf: 1 bbl
mboe	one thousand barrels of oil equivalent
mmboe	one million barrels of oil equivalent
bfpd	barrels of fluid per day
boe/d	barrels of oil equivalent per day
bopd	barrels of oil per day
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day

Other

WTI	West Texas Intermediate
Brent	Brent Ice

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