

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.

"signed"

David R. Taylor

President and Chief Executive Officer

"signed"

Kenneth G. Pinsky

Chief Financial Officer

March 10, 2020



Independent auditor's report

To the Shareholders of Parex Resources Inc.

Our opinion

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of Parex Resources Inc. and its subsidiaries (together, the Company) as at December 31, 2019 and 2018, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board (IFRS).

What we have audited

The Company's consolidated financial statements comprise:

- the consolidated balance sheets as at December 31, 2019 and 2018;
- the consolidated statements of comprehensive income for the years then ended;
- the consolidated statements of changes in equity for the years then ended;
- the consolidated statements of cash flows for the years then ended; and
- the notes to the consolidated financial statements, which include a summary of significant accounting policies.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the consolidated financial statements* section of our report.

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

Independence

We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada. We have fulfilled our other ethical responsibilities in accordance with these requirements.

Other information

Management is responsible for the other information. The other information comprises the Management's Discussion and Analysis and the information, other than the consolidated financial statements and our auditor's report thereon, included in the annual report.

Our opinion on the consolidated financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.



Responsibilities of management and those charged with governance for the consolidated financial statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with IFRS, 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.

In preparing the consolidated financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's responsibilities for the audit of the consolidated financial statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these consolidated financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit 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 Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Company to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.



We also provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

The engagement partner on the audit resulting in this independent auditor's report is John Williamson.

(signed) PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Alberta
March 10, 2020

CONSOLIDATED FINANCIAL STATEMENTS
Consolidated Balance Sheets

As at (thousands of United States dollars)	NOTE	December 31, 2019	December 31, 2018
ASSETS			
Current assets			
Cash and cash equivalents		\$ 396,839	\$ 462,891
Accounts receivable	5	149,510	63,359
Prepays and other current assets		8,363	4,935
Derivative financial instruments	22	511	—
Crude oil inventory	6	653	1,446
		\$ 555,876	\$ 532,631
Deferred tax asset	17	89,254	132,706
Goodwill	10	73,452	73,452
Exploration and evaluation	7	142,916	127,800
Property, plant and equipment	8	823,083	775,531
		\$ 1,684,581	\$ 1,642,120
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities			
Accounts payable and accrued liabilities		\$ 141,716	\$ 160,535
Derivative financial instruments	22	—	8,290
Current income tax payable	17	61,763	135,969
Current portion of decommissioning and environmental liabilities	14	8,366	9,311
		211,845	314,105
Lease obligation	9	770	—
Cash settled share-based compensation liabilities	13	12,379	5,175
Decommissioning and environmental liabilities	14	43,569	48,290
Deferred tax liability	17	13,573	1,518
		282,136	369,088
Shareholders' equity			
Share capital	15	812,684	848,946
Contributed surplus		48,573	54,742
Retained earnings		541,188	369,344
		1,402,445	1,273,032
		\$ 1,684,581	\$ 1,642,120

Commitments and Contingencies (note 24)

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

"signed"
Paul Wright
Director

"signed"
Ron Miller
Director

Consolidated Statements of Comprehensive Income

For the year ended December 31,

(thousands of United States dollars, except per share amounts)

	NOTE	2019	2018
Oil and natural gas sales	11	\$ 1,113,622	\$ 965,723
Royalties		(136,068)	(132,735)
Revenue		977,554	832,988
Commodity risk management contracts (loss)	22	—	(795)
		977,554	832,193
Expenses			
Production		111,061	90,037
Transportation		88,974	57,496
Purchased oil		52,791	12,026
General and administrative		34,214	33,355
Impairment of exploration and evaluation assets	7	22,767	15,172
Equity settled share-based compensation expense	15	7,603	13,529
Cash settled share-based compensation expense	16	20,081	3,165
Depletion, depreciation and amortization	8	125,899	103,306
Foreign exchange loss (gain)	22	6,924	(7,413)
		470,314	320,673
Finance (income)	12	(7,382)	(10,547)
Finance expense	12	10,958	13,841
Net finance expense		3,576	3,294
Income before income taxes		503,664	508,226
Income tax expense			
Current tax expense	17	120,163	246,040
Deferred tax expense (recovery)	17	55,507	(140,718)
		175,670	105,322
Net income and comprehensive income for the year		\$ 327,994	\$ 402,904
Basic net income per common share	18	\$ 2.24	\$ 2.59
Diluted net income per common share	18	\$ 2.20	\$ 2.53

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)

	2019	2018
Share Capital		
Balance, beginning of year	\$ 848,946	\$ 836,166
Issuance of common shares under share-based compensation plans	31,509	25,488
Repurchase of shares	(67,771)	(12,708)
Balance, end of year	\$ 812,684	\$ 848,946
Contributed Surplus		
Balance, beginning of year	\$ 54,742	\$ 52,431
Share-based compensation	7,603	13,529
Options and RSUs exercised	(13,772)	(11,218)
Balance, end of year	\$ 48,573	\$ 54,742
Retained earnings		
Balance, beginning of year	\$ 369,344	\$ (323)
Net income for the year	327,994	402,904
Repurchase of shares	(156,150)	(33,237)
Balance, end of year	541,188	369,344
	\$ 1,402,445	\$ 1,273,032

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	2019	2018
Operating activities			
Net income		\$ 327,994	\$ 402,904
Add (deduct) non-cash items			
Depletion, depreciation and amortization	8	125,899	103,306
Non-cash finance expense	12	6,853	5,884
Equity settled share-based compensation expense	15	7,603	13,529
Cash settled share-based compensation expense	16	20,081	3,165
Deferred tax expense (recovery)	17	55,507	(140,718)
Impairment of exploration and evaluation assets	7	22,767	15,172
Unrealized foreign exchange loss (gain)	22	3,417	(8,029)
Unrealized (gain) on commodity risk management contracts	22	—	(117)
Loss on settlement of decommissioning liabilities	14	359	5,531
Net change in non-cash working capital	19	(205,413)	130,928
Cash provided by operating activities		365,067	531,555
Investing activities			
Property, plant and equipment expenditures	8	(148,519)	(198,820)
Exploration and evaluation expenditures	7	(59,677)	(103,523)
Net change in non-cash working capital	19	(10,796)	27,209
Cash (used in) investing activities		(218,992)	(275,134)
Financing activities			
Issuance of common shares under share-based compensation plans	15	17,736	14,270
Common shares repurchased	15	(223,921)	(45,945)
Payments on lease obligation	9	(592)	—
Net change in non-cash working capital	19	(3,792)	5,838
Cash (used in) financing activities		(210,569)	(25,837)
(Decrease) increase in cash for the year		(64,494)	230,584
Impact of foreign exchange on foreign currency-denominated cash balances		(1,558)	(2,735)
Cash, beginning of year		462,891	235,042
Cash, end of year		\$ 396,839	\$ 462,891

Supplemental Disclosure of Cash Flow Information (note 19)
See accompanying Notes to the Consolidated Financial Statements

Notes to the Consolidated Financial Statements

For the year ended December 31, 2019

(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 10, 2020.

2. Basis of Preparation, Critical Accounting Estimates and Judgements

a) Statement of compliance

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("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 10, 2020, 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 - Property, Plant and Equipment).

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

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 – Exploration and Evaluation Assets).

(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 based on forecast Colombia rates.

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 14 – 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 10 – 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, Cash Settled Restricted Share Units ("CRSU") plan and Cash or share settled Restricted Share Units ("CosRSU") and Performance Share Units ("CosPSU") plan pursuant to which CosRSUs and CosPSUs are measured at fair value based on the market price of Parex shares on the date of issuance. Refer to note 15 - Share Capital and note 16 - 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, 2019. 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 Limited	Bermuda	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.

c) Financial instruments

Effective January 1, 2018, the Company adopted IFRS 9, Financial Instruments and the following accounting policy was in place: Financial instruments are recognized when the Company becomes a party to the contractual provisions of the instrument. Financial assets and liabilities are not offset unless the Company has the current legal right to offset and intends to settle on a net basis or settle the asset and liability simultaneously.

The Company characterizes its fair value measurements into a three-level hierarchy depending on the degree to which the inputs are observable, as follows:

- Level 1 inputs are quoted prices in active markets for identical assets and liabilities;
- Level 2 inputs are inputs, other than quoted prices included within Level 1, that are observable for the asset or liability either directly or indirectly; and
- Level 3 inputs are unobservable inputs for the asset or liability.

Classification and Measurement of Financial Assets

The initial classification of a financial asset depends upon the Company's business model for managing its financial assets and the contractual terms of the cash flows. There are three measurement categories into which the Company classified its financial assets:

- **Amortized Cost:** Includes assets that are held within a business model whose objective is to hold assets to collect contractual cash flows and its contractual terms give rise on specified dates to cash flows that represent solely payments of principal and interest;
- **Fair Value through Other Comprehensive Income ("FVOCI"):** Includes assets that are held within a business model whose objective is achieved by both collecting contractual cash flows and selling the financial assets, where its contractual terms give rise on specified dates to cash flows that represent solely payments of principal and interest; or
- **Fair Value Through Profit or Loss ("FVTPL"):** Includes assets that do not meet the criteria for amortized cost or FVOCI and are measured at fair value through profit or loss. This includes all derivative financial instruments.

On initial recognition, the Company may irrevocably designate a financial asset that meets the amortized cost or FVOCI criteria as measured at FVTPL if doing so eliminates or significantly reduces an accounting mismatch. On initial recognition of an equity investment that is not held-for-trading, the Company may irrevocably elect to present subsequent changes in the investment's fair value in OCI. There is no subsequent reclassification of fair value changes to earnings following the derecognition of the investment. However, dividends that reflect a return on investment continue to be recognized in net earnings. This election is made on an investment-by-investment basis.

At initial recognition, the Company measures a financial asset at its fair value and, in the case of a financial asset not at FVTPL, including transaction costs that are directly attributable to the acquisition of the financial asset. Transaction costs of financial assets carried at FVTPL are recorded as an expense in net earnings.

Financial assets are reclassified subsequent to their initial recognition only if the business model for managing those financial assets changes. The affected financial assets will be reclassified on the first day of the first reporting period following the change in the business model. A financial asset is derecognized when the rights to receive cash flows from the asset have expired or have been transferred and the Company has transferred substantially all the risks and rewards of ownership.

Impairment of Financial Assets

The Company recognizes loss allowances for Expected Credit Losses ("ECLs") on its financial assets measured at amortized cost. Due to the nature of its financial assets, the Company measures loss allowances at an amount equal to expected lifetime ECLs. Lifetime ECLs are the anticipated ECLs that result from all possible default events over the expected life of a financial asset. ECLs are a probability-weighted estimate of credit losses. Credit losses are measured as the present value of all cash shortfalls (i.e. the difference between the cash flows due to the entity in accordance with the contract and the cash flows that the Company expects to receive). ECLs are discounted at the effective interest rate of the related financial asset. The Company does not have any financial assets that contain a financing component.

As at December 31, 2019, all of the Company's receivables were outstanding for less than 90 days. The average expected credit loss on the Company's trade accounts receivable was 0.31 percent at December 31, 2019.

Classification and Measurement of Financial Liabilities

A financial liability is initially classified as measured at amortized cost or FVTPL. A financial liability is classified as measured at FVTPL if it is held-for-trading, a derivative, or designated as FVTPL on initial recognition. The classification of a financial liability is irrevocable.

Financial liabilities at FVTPL are measured at fair value with changes in fair value, along with any interest expense, recognized in net earnings. Other financial liabilities are initially measured at fair value less directly attributable transaction costs and are subsequently measured at amortized cost using the effective interest method. Interest expense and foreign exchange gains and losses are recognized in net earnings. Any gain or loss on derecognition is also recognized in net earnings.

A financial liability is derecognized when the obligation is discharged, cancelled or expired. When an existing financial liability is replaced by another from the same counterparty with substantially different terms, or the terms of an existing liability are substantially modified, it is treated as a derecognition of the original liability and the recognition of a new liability. When the terms of an existing financial liability are altered, but the

changes are considered non-substantial, it is accounted for as a modification to the existing financial liability. Where a liability is substantially modified it is considered to be extinguished and a gain or loss is recognized in net earnings based on the difference between the carrying amount of the liability derecognized and the fair value of the revised liability. Where a liability is modified in a non-substantial way, the amortized cost of the liability is remeasured based on the new cash flows and a gain or loss is recorded in net earnings.

Derivative Financial Instruments

Derivative financial instruments are used to manage economic exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. Policies and procedures are in place with respect to required documentation and approvals for the use of derivative financial instruments. Where specific financial instruments are executed, the Company assesses, both at the time of purchase and on an ongoing basis, whether the financial instrument used in the particular transaction is effective in offsetting changes in fair values or cash flows of the transaction.

Risk management assets and liabilities are derivative financial instruments classified as measured at FVTPL unless designated for hedge accounting. Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded using mark-to-market accounting whereby instruments are recorded in the consolidated balance sheets as either an asset or liability with changes in fair value recognized in net earnings as a gain or loss on risk management. The estimated fair value of all derivative instruments is based on quoted market prices or, in their absence, third-party market indications and forecasts.

Prior to the adoption of IFRS 9, Financial Instruments on January 1, 2018 the following accounting policy was in place: 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 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 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. 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.

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.

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.

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 and are not reversed. Goodwill is reported at cost less any impairment.

i) Revenue recognition

Parex principally generates revenue from the sale of commodities, which include crude oil and natural gas. Revenue associated with the sale of commodities is recognized when control is transferred from Parex to its customers. The Company's commodity sale contracts represent a series of distinct transactions. The Company considers its performance obligations to be satisfied and control to be transferred when all the following conditions are satisfied:

- Parex has transferred title and physical possession of the commodity to the buyer;
- Parex has transferred the significant risks and rewards of ownership of the commodity to the buyer; and
- Parex has the present right to payment.

Revenue is measured based on the consideration specified in a contract with a customer and excludes amounts collected on behalf of third parties. The Company sells its production of crude oil and natural gas pursuant to variable price contracts. The transaction price for variable price contracts is based on the commodity price, adjusted for quality, location and other factors. The amount of revenue recognized is based on the agreed transaction price with any variability in transaction price recognized in the same period. The Company does not have any contracts where the period between the transfer of the promised goods or services to the customer and payment by the customer exceeds one year. As a result, Parex does not adjust its revenue transactions for the time value of money.

Parex enters into contracts with customers that can have performance obligations that are unsatisfied (or partially unsatisfied) at the reporting date. The Company applies a practical expedient of IFRS 15 and does not disclose information about remaining performance obligations that have original expected durations of one year or less, or for performance obligations where the Company has a right to consideration from a customer in an amount that corresponds directly with the value to the customer of the Company's performance completed to date. The Company also applies a practical expedient of IFRS 15 that allows any incremental costs of obtaining contracts with customers to be recognized as an expense when incurred rather than being capitalized.

Contract modifications with the Company's customers could change the scope of the contract, the price of the contract, or both. A contract modification exists when the parties to the contract approve the modification either in writing, orally, or based on the parties' customary business practices. Contract modifications are accounted for either as a separate contract when there is an additional product at a stand alone selling price, or as part of the existing contract, through either a cumulative catch-up adjustment or prospectively over the remaining term of the contract, depending on the nature of the modification and whether the remaining products are distinct.

The Company's revenue transactions do not contain significant financing components.

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 15 - Share Capital. 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 16 - Cash Settled Incentive Plans. 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 16 - Cash Settled Incentive Plans. 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.

The Company has a Deferred Share Unit ("DSU") plan which allows the Company to issue DSUs to all non-employee directors of Parex Resources Inc, as described in note 16 - Cash Settled Incentive Plans. 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.

During the year the Company put in place a Cash or Share Settled Restricted Share Unit/Performance Share Unit ("CosRSU/CosPSU") incentive plan to issue CosRSUs and CosPSUs to certain employees of Parex Canada as described in note 16 - Cash Settled Incentive Plans. This new plan will replace the equity settled RSU/PSU plan. Obligations for payments of cash or settlement of shares under the CosRSUs and CosPSUs plan are accrued as compensation expense over the vesting period based on the fair value of the CosRSUs and CosPSUs. The fair value of CosRSUs and CosPSUs 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 CosRSUs and CosPSUs 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 CosRSUs and CosPSUs liability can be settled in cash or by the issuance of common shares at the election of the employee.

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 in Colombia and the Caribbean 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.

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 accounting standards adopted

The following new accounting standards were adopted by the Company effective January 1, 2019:

(i) Adoption of IFRS 16, Leases

Effective January 1, 2019, the Company adopted IFRS 16 Leases ("IFRS 16"), which replaces previous IFRS guidance on leases: IAS 17 Leases ("IAS 17"). Under IAS 17, lessees were required to determine if the lease was a finance or operating lease, based on specified criteria of whether the lease transferred significantly all the risks and rewards associated with ownership of the underlying asset. Finance leases were recognized on the consolidated balance sheet while operating leases were recognized in net income and comprehensive income in the consolidated statements of comprehensive income. IFRS 16 introduced a single lease accounting model for lessees which requires a right-of-use asset and liability to be recognized on the balance sheet for contracts that are, or contain, a lease. The Company adopted IFRS 16 using the modified retrospective approach, whereby the cumulative effect of initially applying the standard was recognized as a \$2.2 million increase to right-of-use assets (included in "Property, Plant and Equipment") with a corresponding increase to lease obligations (the non-current portion of \$1.5 million is recorded in "Lease Obligation" and the current portion of \$0.7 million is recorded in "accounts payable and accrued liabilities"). On adoption of IFRS 16, the Company's lease liabilities related to contracts classified as a lease are measured at the discounted present value of the remaining minimum lease payments, excluding short-term and low-value leases. The right-of-use assets recognized were measured at amounts equal to the present value of the lease obligations. The weighted average incremental borrowing rate used to determine the lease obligation at adoption was approximately 5.0%. The right-of-use asset and lease obligation recognized relate to the Company's head office lease in Calgary, Alberta. The Company elected to not apply lease accounting to certain leases for which the lease term ends within 12 months of the date of initial application. The measurement of lease obligations are subject to management's judgment and the application of the incremental borrowing rate.

Of the \$9.5 million operating lease commitments as at December 31, 2018, \$2.2 million related to lease obligations recognized as at January 1, 2019. Non-lease components were \$6.5 million and \$0.8 million related to short-term and low-value leases.

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, 2019 and 2018 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 15 - Share Capital.

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 16 - Cash Settled Incentive Plans.

e) Restricted share units, performance share units, cash settled restricted share units, cash or share settled restricted share units and performance 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 15 - Share Capital and note 16 - Cash Settled Incentive Plans.

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, 2019	December 31, 2018
Trade receivables	\$ 143,577	\$ 55,987
Value added taxes (VAT)	5,933	7,372
	\$ 149,510	\$ 63,359

Trade receivables consist primarily of oil sale receivables related to the Company's oil sales. VAT receivable is \$5.9 million as at December 31, 2019 (December 31, 2018 - \$7.4 million) and is recoverable within one year. All accounts receivable are expected to be received within twelve months and are thus recognized as current assets.

6. Inventory

	December 31, 2019	December 31, 2018
Crude oil inventory	\$ 653	\$ 1,446

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 2019 \$1.4 million (year ended December 31, 2018 - \$3.0 million) of produced crude oil inventory cost was expensed to the consolidated statements of comprehensive income. Purchased crude oil is sold immediately. The cost associated with purchased oil is shown in the consolidated statements of comprehensive income as purchased oil expense.

7. Exploration and Evaluation Assets

Cost		
Balance at December 31, 2017	\$	107,144
Additions		103,523
Transfers to PP&E		(68,484)
Changes in decommissioning liability		789
Exploration and evaluation impairment		(15,172)
Balance at December 31, 2018	\$	127,800
Additions		59,677
Transfers to PP&E		(25,590)
Changes in decommissioning liability		3,796
Exploration and evaluation impairment		(22,767)
Balance at December 31, 2019	\$	142,916

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, 2019 additions of \$59.7 million (year ended December 31, 2018 - \$103.5 million) represent the Company's share of costs incurred on E&E assets during the period. During the year ended December 31, 2019 \$25.6 million of E&E assets were transferred to PP&E mainly related to the Boranda Block. During the year ended December 31, 2018 - \$68.5 million of E&E assets were transferred to PP&E mainly related to the Capachos Block.

2019 Impairments

During 2019, 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 the LLA-10 block and the Morpho block won't be recovered as the Company plans to relinquish or has already relinquished the block, respectively. 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 \$22.8 million which is recorded in the consolidated statements of comprehensive income for the year ended December 31, 2019.

2018 Impairments

During 2018, 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-9 block in the Middle Magdalena basin were unlikely to be recovered by successful development or sale as the block is currently in force majeure and could be for the foreseeable future. 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 \$15.2 million which is recorded in the consolidated statements of comprehensive income for the year ended December 31, 2018.

At December 31, 2019 and December 31, 2018 the Company did not have any E&E assets in Canada.

8. Property, Plant and Equipment

	Canada	Colombia	Total
Cost			
Balance at December 31, 2017	\$ 3,780	\$ 1,787,822	\$ 1,791,602
Additions	87	198,733	198,820
Transfers from E&E assets	—	68,484	68,484
Changes in decommissioning and environmental liability	—	9,841	9,841
Balance at December 31, 2018	3,867	2,064,880	2,068,747
Additions	121	148,398	148,519
Right-of-use asset addition (non-cash)	2,227	—	2,227
Transfers from E&E assets	—	25,590	25,590
Changes in decommissioning and environmental liability	—	(3,077)	(3,077)
Balance at December 31, 2019	\$ 6,215	\$ 2,235,791	\$ 2,242,006
Accumulated Depreciation, Depletion and Amortization			
Balance at December 31, 2017	\$ 3,533	\$ 1,186,632	\$ 1,190,165
Depletion and depreciation for the year	145	103,161	103,306
DD&A included in crude oil inventory costing	—	(255)	(255)
Balance at December 31, 2018	3,678	1,289,538	1,293,216
Depletion and depreciation for the year	136	124,996	125,132
Depreciation - Right-of-use asset	767	—	767
DD&A included in crude oil inventory costing	—	(192)	(192)
Balance at December 31, 2019	\$ 4,581	\$ 1,414,342	\$ 1,418,923
Net book value:			
As at December 31, 2017	\$ 247	\$ 601,190	\$ 601,437
As at December 31, 2018	\$ 189	\$ 775,342	\$ 775,531
As at December 31, 2019	\$ 1,634	\$ 821,449	\$ 823,083

Additions and Transfers

During 2019, property, plant and equipment ("PPE") additions of \$148.5 million mainly relate to drilling costs in Colombia at Blocks LLA-34, LLA-32 Cabrestero and Capachos and facility costs at Blocks LLA-34, Capachos and Aguas Blancas. During the year ended December 31, 2018, additions of \$198.8 million mainly related to drilling costs in Colombia at Block LLA-34, Cabrestero block and the Aguas Blancas block. For the year ended December 31, 2019, \$25.6 million of E&E assets were transferred to PP&E related to the Boranda Block (year ended December 31, 2018 - \$68.5 million E&E assets were transferred to PP&E related to the Capachos Block).

For the year ended December 31, 2019 future development costs of \$453.1 million (year ended December 31, 2018 - \$411.7 million) were included in the depletion calculation for development and production assets. For the year ended December 31, 2019 \$10.2 million of general and administrative costs (year ended December 31, 2018 - \$9.5 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, 2019 and 2018 there was no indication of impairment noted.

9. Lease Obligation

The Company has the following future commitments associated with its office lease obligation:

	December 31, 2019
Less than 1 year	\$ 932
2-3 years	790
Total lease payments	1,722
Amounts representing interest over the term of the lease	(85)
Present value of net lease payments	1,637
Current portion of lease obligations	(867)
Non-current portion of lease obligations	\$ 770

The consolidated statements of comprehensive income for the year ended December 31, 2019 includes expenses related to leases as follows: \$0.1 million of interest expense related to the lease obligation, \$0.8 million of depreciation for right-of-use assets, \$0.6 million of non-lease components associated with the office lease obligation and \$0.8 million related to short-term and low value leases.

Total cash outflows were \$2.1 million for the year ended December 31, 2019.

10. Goodwill

	December 31, 2019	December 31, 2018
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 - Summary of Significant Accounting Policies. 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, 2019 are as follows:

	2020	2021	2022	2023	2024	Thereafter
Brent (\$US/bbl)	67.00	68.00	71.00	73.00	75.00	2% increase per year

Prices used at December 31, 2018 are as follows:

	2019	2020	2021	2022	2023	Thereafter
Brent (\$US/bbl)	63.25	68.50	71.25	73.00	75.50	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, 2018 - 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. Revenue

The Company's oil and natural gas production revenue is determined pursuant to the terms of the revenue agreements. The transaction price for crude oil and natural gas is based on the commodity price in the month of production, adjusted for quality, location, allowable deductions, if any, or other factors. Commodity prices are based on market indices that are determined on a monthly or daily basis.

The Company's oil and natural gas revenues by product are as follows:

For the year ended December 31,	2019	2018
Crude oil	\$ 1,101,060	\$ 956,231
Natural gas	12,562	9,492
Oil and natural gas sales	\$ 1,113,622	\$ 965,723

At December 31, 2019, receivables from contracts with customers, which are included in accounts receivable, were \$143.6 million (December 31, 2018 - \$56.0 million).

12. Net Finance Expense

For the year ended December 31,	2019	2018
Bank charges and credit facility fees	\$ 3,647	\$ 2,426
Accretion on decommissioning and environmental liabilities	4,592	4,888
Interest and other income	(7,382)	(10,547)
Right of use asset interest	99	—
Loss on settlement of decommissioning liabilities	359	5,531
Loss on disposition of tangible assets	235	996
Other	2,026	—
Net finance expense	\$ 3,576	\$ 3,294

For the year ended December 31,	2019	2018
Non-cash finance expense	\$ 7,212	\$ 11,415
Cash finance (income)	(3,636)	(8,121)
Net finance expense	\$ 3,576	\$ 3,294

13. Cash Settled Share-Based Compensation Liabilities

Cash settled share-based compensation liabilities are comprised of the following:

	December 31, 2019	December 31, 2018
Long-term SARs payable	\$ —	\$ 91
Long-term DSUs payable	4,496	2,748
Long-term CRSUs payable	4,004	2,336
Long-term CosRSUs and CosPSUs payable	3,879	—
Total cash settled-share based compensation payable	\$ 12,379	\$ 5,175

14. Decommissioning and Environmental Liabilities

	Decommissioning		Environmental		Total
Balance, December 31, 2017	\$ 36,774	\$ 15,906	\$ 52,680		
Additions	7,974	6,146	14,120		
Settlements of obligations during the year	(8,060)	(2,352)	(10,412)		
Loss on settlement of obligations	5,531	—	5,531		
Accretion expense	2,657	2,231	4,888		
Change in estimate - inflation and discount rates	(1,703)	(139)	(1,842)		
Change in estimate - costs	2,604	(4,252)	(1,648)		
Foreign exchange gain	(3,725)	(1,991)	(5,716)		
Balance, December 31, 2018	\$ 42,052	\$ 15,549	\$ 57,601		
Additions	10,524	1,355	11,879		
Settlements of obligations during the year	(10,536)	(1,229)	(11,765)		
Loss on settlement of obligations	359	—	359		
Accretion expense	3,166	1,426	4,592		
Change in estimate - inflation and discount rates	1,455	170	1,625		
Change in estimate - costs	(10,253)	(2,532)	(12,785)		
Foreign exchange loss (gain)	477	(48)	429		
Balance, December 31, 2019	37,244	14,691	51,935		
Current obligation	(4,275)	(4,091)	(8,366)		
Long-term obligation	\$ 32,969	\$ 10,600	\$ 43,569		

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, 2019, 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 \$63.3 million as at December 31, 2019 (December 31, 2018 – \$70.3 million) with the majority of these costs anticipated to occur in 2022 or later. A risk-free discount rate of 6.74 percent and an inflation rate of 3.1 percent were used in the valuation of the liabilities (December 31, 2018 – 7.5 percent risk-free discount rate and a 3.2 percent inflation rate). The risk-free discount rate and the inflation rate used in 2019 are based on forecast Colombia rates.

Included in the decommissioning liability is \$4.3 million (December 31, 2018 – \$6.6 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 \$21.5 million as at December 31, 2019 (December 31, 2018 – \$20.8 million) with the majority of these costs anticipated to occur in 2020 or later in Colombia. A risk-free discount rate of 6.74 percent and an inflation rate of 3.1 percent were used in the valuation of the liabilities (December 31, 2018 – 7.5 percent risk-free discount rate and a 3.2 percent inflation rate). The risk-free discount rate and the inflation rate used in 2019 are based on forecast Colombia rates.

Included in the environmental liability is \$4.1 million (December 31, 2018 – \$2.7 million) that is classified as a current obligation.

15. Share Capital

a) Issued and outstanding common shares

	Number of shares	Amount
Balance, December 31, 2017	154,742,134	\$ 836,166
Issued for cash – exercise of options and RSUs	3,017,354	14,270
Allocation of contributed surplus – exercise of options and RSUs	—	11,218
Repurchase of shares	(2,745,580)	\$(12,708)
Balance, December 31, 2018	155,013,908	848,946
Issued for cash – exercise of options and RSUs	2,960,620	17,736
Allocation of contributed surplus – exercise of options and RSUs	—	13,772
Repurchase of shares	(14,679,474)	(67,771)
Balance, December 31, 2019	143,295,054	\$ 812,683

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

In 2019, a total of 2,960,620 options and RSUs were exercised for proceeds of \$17.7 million (year ended December 31, 2018 - 3,017,354 options and RSUs were exercised for \$14.3 million).

In 2019, the Company repurchased 14,679,474 common shares pursuant to its Normal Course Issuer Bid for \$223.9 million at an average cost per share of Cdn\$20.41 (year ended December 31, 2018 - 2,745,580 common shares repurchased for \$45.9 million at an average cost per share of Cdn\$19.95). 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 reserved for issuance under the stock option plan may not exceed 9 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, 2017	6,479,435	11.13
Granted	193,650	18.52
Exercised	(2,301,471)	7.92
Forfeited	(29,867)	13.61
Balance, December 31, 2018	4,341,747	13.14
Granted	228,300	19.23
Exercised	(2,104,304)	11.12
Balance, December 31, 2019	2,465,743	15.42

Stock options outstanding and the weighted average remaining life of the stock options at December 31, 2019 are as follows:

Exercise price Cdn\$	Options outstanding			Options vested		
	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
\$10.94 - \$15.59	492,702	1.00	11.31	461,984	0.91	11.06
\$15.60 - \$15.84	1,027,770	1.87	15.66	1,027,770	1.87	15.66
\$15.85 - \$17.13	525,271	2.19	16.02	333,807	2.19	16.02
\$17.14 - \$18.64	191,700	3.11	18.52	62,594	3.11	18.52
\$18.65 - \$21.08	228,300	4.17	19.23	—	—	—
	2,465,743	2.07	15.42	1,886,155	1.73	14.69

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,	2019	2018
Risk-free interest rate (%)	1.75	1.93
Expected life (years)	4	4
Expected volatility (%)	40	43
Forfeiture rate (%)	3	3
Expected dividends	—	—

The weighted average fair value at the grant date for the year ended December 31, 2019 was Cdn\$6.42 per option (year ended December 31, 2018 – Cdn\$6.68 per option). The weighted average share price on the exercise date for options exercised in 2019 was Cdn\$21.62 (year ended December 31, 2018 – Cdn\$19.52).

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.

In 2019 the Company put in place a new Cash or Share settled RSU/PSU plan ("CosRSU") which will replace this equity settled RSU/PSU plan.

	Number of RSU's	Weighted average exercise price Cdn\$/RSU
Balance, December 31, 2017	2,730,295	0.01
Granted	537,025	0.01
Exercised	(715,883)	0.01
Forfeited	(24,369)	0.01
Balance, December 31, 2018	2,527,068	0.01
Exercised	(856,316)	0.01
Forfeited	(7,434)	0.01
Balance, December 31, 2019	1,663,318	0.01

RSUs outstanding and the weighted average remaining life of the RSUs at December 31, 2019 are as follows:

Exercise price Cdn\$	RSUs outstanding		RSUs vested	
	Number of RSUs	Weighted average remaining life (years)	Number of RSUs	Weighted average remaining life (years)
0.01	1,663,318	2.06	1,112,170	1.70

The fair value of each RSU granted is based on the market price of Parex shares on the date of issuance. There were no RSUs granted during the year ended December 31, 2019. The weighted average fair value at the grant date for the year ended December 31, 2018 was Cdn\$18.57 per RSU. For the year ended December 31, 2019 a weighted average forfeiture rate of 3% was applied (year ended December 31, 2018 – 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 performance multiplier has been determined. 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.

	Number of PSU's	Weighted average exercise price Cdn\$/PSU
Balance, December 31, 2017	103,500	0.01
Granted	217,000	0.01
Balance, December 31, 2018	320,500	0.01
Balance, December 31, 2019	320,500	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. There were no PSUs granted during the year ended December 31, 2019. The weighted average fair value at the grant date for the year ended December 31, 2018 was Cdn\$18.52 per PSU.

d) Equity settled share-based compensation

For the year ended December 31,		2019		2018
Option expense	\$	1,867	\$	3,303
Restricted and performance share units expense		5,736		10,226
Total equity settled share-based compensation expense	\$	7,603	\$	13,529

16. 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, 2017	2,388,007	13.38
Exercised	(715,495)	12.12
Forfeited	(80,646)	14.54
Balance, December 31, 2018	1,591,866	13.90
Exercised	(989,225)	13.33
Forfeited	(33,869)	15.42
Balance, December 31, 2019	568,772	14.80

As at December 31, 2019 531,844 SARs were vested (December 31, 2018 – 1,077,326 SARs were vested).

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,	2019	2018
Risk-free interest rate (%)	1.71	1.85
Expected life (years)	1	2
Expected volatility (%)	34	41
Share price (\$/Cdn)	24.15	16.35
Expected dividends	—	—

As at December 31, 2019, the total SARs liability accrued is \$4.6 million (December 31, 2018 - \$5.9 million) of which \$nil (December 31, 2018 - \$0.1 million) is classified as long-term in accordance with the three-year vesting period.

b) Deferred share units ("DSUs")

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, 2017	193,975	—
Granted	48,475	—
Exercised on board retirement	(23,100)	—
Balance, December 31, 2018	219,350	—
Granted	26,435	—
Balance, December 31, 2019	245,785	—

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, 2019 was Cdn \$21.47 per DSU (year ended December 31, 2018 - Cdn\$22.94 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, 2019 the total DSUs liability accrued is \$4.5 million (December 31, 2018 - \$2.7 million) all of which 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, 2017	492,350	—
Granted	487,075	—
Exercised	(161,607)	—
Forfeited	(32,743)	—
Balance, December 31, 2018	785,075	—
Granted	551,020	—
Exercised	(306,251)	—
Forfeited	(38,174)	—
Balance, December 31, 2019	991,670	—

The weighted average fair value at the grant date for the year ended December 31, 2019 was Cdn\$19.19 per CRSU (year ended December 31, 2018 - Cdn\$18.57 per CRSU).

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, 2019, the total CRSUs liability accrued is \$11.8 million (December 31, 2018 - \$5.4 million) of which \$4.0 million (December 31, 2018 - \$2.3 million) is classified as long-term in accordance with the three-year vesting period.

d) Cash or share settled Restricted Share Units and Performance Share Units ("CosRSU and CosPSU")

In 2019 Parex put in place a new Cash or share settled RSU/PSU incentive plan. This new plan will replace the equity settled RSU/PSU plan. This plan provides for the issuance of RSUs and PSUs to certain employees of Parex Canada. 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 or the employee can elect to receive the award in Parex common shares. CosRSUs and CosPSUs vest over a three-year period and are exercised at the vest date.

CosRSU:

	Number of CosRSUs
Balance, December 31, 2018	—
Granted	655,185
Forfeited	(6,000)
Balance, December 31, 2019	649,185

CosPSU:

	Number of CosPSUs
Balance, December 31, 2018	—
Granted	222,100
Balance, December 31, 2019	222,100

As at December 31, 2019, no CosRSUs and CosPSUs were vested.

The weighted average fair value at the grant date for the year ended December 31, 2019 was Cdn\$19.50 per CosRSU and CosPSU.

Obligations for payments of cash under the CosRSUs and CosPSUs plans are accrued as compensation expense over the vesting period based on the fair value of RSUs and PSUs. The fair value of CosRSUs and CosPSUs is equivalent to the trading value of a common share of the Company on the valuation date. As at December 31, 2019, the total CosRSUs and CosPSUs liability accrued is \$7.1 million (December 31, 2018 - \$nil) of which \$3.9 million (December 31, 2018 -\$nil) is classified as long-term in accordance with the three-year vesting period.

e) Cash settled share-based compensation

For the year ended December 31,	2019	2018
SARs expense (recovery)	\$ 1,784	\$ (2,227)
CRSUs expense	9,460	5,126
DSUs expense	1,748	266
CosRSUs and CosPSUs expense	7,089	—
Total cash settled-share based compensation expense	\$ 20,081	\$ 3,165
Cash payments made upon exercise	\$ 9,173	\$ 7,274

17. Income Tax

The components of tax expense for 2019 and 2018 were as follows:

For the year ended December 31,	2019	2018
Current tax expense	\$ 120,987	\$ 245,951
Adjustments in respect of prior period	(824)	89
Total current tax expense	\$ 120,163	\$ 246,040
Deferred tax (recovery)	55,507	(140,718)
Total tax expense	\$ 175,670	\$ 105,322

Factors affecting tax expense for the year

The standard Colombian corporate income tax rate for 2019 was 33 percent (year ended December 31, 2018 – 37 percent). The following is a reconciliation of income taxes calculated at the Colombian corporate tax rate to the tax expense for 2019 and 2018:

For the year ended December 31,	2019	2018
Income before tax	\$ 503,664	\$ 508,226
Income before tax multiplied by the standard rate of Colombian corporate tax of 33% (2018 – 37%)	166,209	188,044
Effects of:		
Income taxes recorded at rates different from the Colombian tax rate	(1,082)	(5,354)
Impact of Colombian tax rate changes	(134)	(1,762)
Impact of deferred tax rate changes	860	—
Income/expenses taxable/deductible at different rates	—	(81,528)
Non-deductible expense and other permanent differences	9,059	(44,887)
Share-based compensation	4,110	3,725
Adjustment in respect of prior period	(1,178)	3,277
Foreign exchange impact on tax pools denominated in foreign currency	(2,187)	43,388
Change in unrecognized deferred tax assets	13	419
Total tax expense	\$ 175,670	\$ 105,322

The Colombian government enacted legislation in December 2019 containing tax rate changes effective January 1, 2020. Colombian current tax rates are as follows: 32% for 2020; 31% in 2021, and 30% thereafter.

The analysis of deferred income tax assets as follows:

	December 31, 2019	December 31, 2018
Deferred tax assets to be settled within 12 months	\$ 1,092	\$ 103
Deferred tax assets to be settled after more than 12 months	88,162	132,603
Deferred income tax assets	\$ 89,254	\$ 132,706

The analysis of deferred income tax liabilities as follows:

	December 31, 2019	December 31, 2018
Deferred tax liabilities to be settled within 12 months	\$ (9,556)	\$ (8,250)
Deferred tax liabilities to be settled after more than 12 months	23,129	9,768
Deferred income tax liability	\$ 13,573	\$ 1,518
Net deferred tax liability (asset)	\$ (75,681)	\$ (131,188)

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, 2019	Charged (credited) to the statement of comprehensive income /(loss)	December 31, 2018	Charged (credited) to the statement of comprehensive income /(loss)
PP&E	\$ (31,750)	\$ (9,525)	\$ (22,225)	\$ 33,275
Decommissioning liability	10,149	(1,399)	11,548	(6,476)
Cash-settled equity based compensation	4,908	1,510	3,398	(1,155)
Other	3,120	(2,641)	5,761	3,183
Balance, end of period	\$ (13,573)	\$ (12,055)	\$ (1,518)	\$ 28,827

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

Deferred Tax Asset	December 31, 2019	Charged (credited) to the statement of comprehensive income /(loss)	December 31, 2018	Charged (credited) to the statement of comprehensive income /(loss)
PP&E	\$ 77,250	\$ (36,307)	\$ 113,557	\$ 114,144
Loss carry forwards	5,839	(7,336)	13,175	(7,477)
Decommissioning liability	5,683	(341)	6,024	5,970
Other	482	532	(50)	(746)
Balance, end of period	\$ 89,254	\$ (43,452)	\$ 132,706	\$ 111,891

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. At December 31, 2019 the deferred tax asset amount recorded in Canada is \$6.5 million. The Company did not recognize deferred income tax assets on capital losses and other items in Canada of \$150.4 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, 2019 exchange rate. At December 31, 2019 the Company had the following losses carry-forward:

	Canada
Year of expiry	
2032	\$ 6,027
2033	4,811
2034	2,365
2035	9,344
2036	808
Indefinitely	167,116
	\$ 190,471

Earnings retained by subsidiaries amounted to \$772.3 million at December 31, 2019 (December 31, 2018 - \$445.8 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.

18. Net income per Share

a) Basic net income per share

For the year ended December 31,	2019	2018
Net income		
Net income for the purpose of basic net income per share	\$ 327,994	\$ 402,904
Weighted average number of shares for the purposes of basic net income per share (000's)	146,380	155,417
Basic net income per share	\$ 2.24	\$ 2.59

b) Diluted net income per share

For the year ended December 31,	2019	2018
Net income		
Net income used to calculate diluted net income per share	\$ 327,994	\$ 402,904
Weighted average number of shares for the purposes of basic net income per share (000's)	146,380	155,417
Dilutive effect of share options and RSUs on potential common shares	2,645	4,145
Weighted average number of shares for the purposes of diluted net income per share	149,025	159,562
Diluted net income per share	\$ 2.20	\$ 2.53

For the year ended December 31, 2019, 228,300 stock options (December 31, 2018 - nil) were excluded from the diluted weighted average shares calculation as they were anti-dilutive.

19. Supplemental Disclosure of Cash Flow Information

a) Net change in non-cash working capital

For the year ended December 31,	2019	2018
Accounts receivable	\$ (86,151)	\$ (21,050)
Prepays and other current assets	(3,428)	(3,107)
Crude oil inventory	793	1,592
Accounts payable and accrued liabilities	(119,259)	197,207
Depletion related to crude oil inventory	(192)	(255)
Decommissioning and environmental liabilities	(11,765)	(10,412)
Net change in non-cash working capital	\$ (220,002)	\$ 163,975
Operating	\$ (205,413)	\$ 130,928
Investing	(10,796)	27,209
Financing	(3,792)	5,838
Net change in non-cash working capital	\$ (220,001)	\$ 163,975

b) Interest and taxes paid

For the year ended December 31,	2019	2018
Cash interest paid	\$ —	\$ 1,472
Cash income taxes paid	\$ 136,251	\$ 14,838

20. Employee Salaries and Benefit Expenses

For the year ended December 31,	2019	2018
Salaries, bonuses and other short-term benefits	\$ 30,961	\$ 31,757
Equity settled share-based compensation	7,603	13,529
Cash settled share-based compensation	20,081	3,165
	\$ 58,645	\$ 48,451

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

21. 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.

Parex has a senior secured credit facility which at December 31, 2019 had a borrowing base in the amount of \$200.0 million (December 31, 2018 - \$200.0 million). The credit facility is intended to serve as means to increase liquidity and fund cash or letter of credit needs as they arise. As at December 31, 2019, \$nil (December 31, 2018 - \$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") related to the exploration work commitments on its Colombian concessions (see note 24 - Commitments). This performance guarantee facility has a limit of \$150.0 million (December 31, 2018 - limit of \$150.0 million) of which \$25.4 million (December 31, 2018 - \$79.7 million) is utilized at December 31, 2019. At December 31, 2019, there is an additional \$22.5 million (December 31, 2018 - \$31.9 million) of letters of credit that are provided by a Latin American bank on an unsecured basis.

As at December 31, 2019 the Company's net working capital surplus was \$344.0 million (December 31, 2018 - \$218.5 million), of which \$396.8 million is cash.

On December 19, 2019 the Toronto Stock Exchange ("TSX") approved the Company's NCIB application to purchase up to 13,986,994 of the Company's common shares for cancellation.

On December 18, 2018 the Toronto Stock Exchange ("TSX") approved the Company's NCIB application to purchase up to 15,041,319 of the Company's common shares for cancellation and the Company repurchased the maximum amount of shares by October 11, 2019.

Parex has the ability to adjust its capital structure by issuing new equity or debt and making adjustments to its capital expenditure and share buy back programs to the extent the capital expenditures are not committed. The Company considers its capital structure at this time to include shareholders' equity, the credit facility and its working capital. As at December 31, 2019 shareholders' equity was \$1,402.4 million (December 31, 2018 - \$1,273.0 million).

22. 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. Financial derivative instruments, specifically fixed price contracts, 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, 2019.

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 and foreign currency 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 and foreign currency, using quoted market prices or the period end forward price for the same commodity and foreign currency, 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, 2019 had the majority of its oil sales to 10 counterparties. Accounts receivable balance as at December 31, 2019 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, 2019 there are no accounts receivable past due (December 31, 2018 - \$nil).

As at December 31, 2019 and 2018 the Company's accounts receivable are aged as follows:

For the year ended December 31,	2019	2018
Current (less than 90 days)	\$ 149,510	\$ 63,359
Past due (more than 90 days)	—	—
Total	\$ 149,510	\$ 63,359

None of the Company's receivables are impaired at December 31, 2019. 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 \$200.0 million credit facility at December 31, 2019 was \$nil.

The following are the contractual maturities of financial liabilities at December 31, 2019:

	Less than 1 year	2-3 Years	4-5 Years	Thereafter	Total
Accounts payable and accrued liabilities ⁽¹⁾	\$ 125,282	—	—	—	\$ 125,282
Current income tax payable	61,763	—	—	—	61,763
Lease obligation	867	770	—	—	1,637
Cash settled equity plans payable	15,567	12,379	—	—	27,946
Total	\$ 203,479	13,149	—	—	\$ 216,628

⁽¹⁾ Includes the liability for derivative financial instruments.

The following are the contractual maturities of financial liabilities at December 31, 2018:

	Less than 1 year	2-3 Years	4-5 Years	Thereafter	Total
Accounts payable and accrued liabilities ⁽¹⁾	\$ 159,925	—	—	—	\$ 159,925
Current income tax payable	135,969	—	—	—	135,969
Cash settled equity plans payable	8,900	5,175	—	—	14,075
Total	\$ 304,794	5,175	—	—	\$ 309,969

⁽¹⁾ Includes the liability for derivative financial instruments.

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, 2019 the Company had no outstanding commodity risk management contracts.

The table below summarizes the loss on the commodity risk management contracts that were in place during the year ended December 31, 2019 and 2018:

For the year ended December 31,	2019	2018
Premiums paid on commodity risk management contracts	\$ —	\$ 912
Unrealized (gain) on commodity risk management contracts	—	(117)
Total	\$ —	\$ 795

d) Foreign currency risk

The Company is exposed to foreign currency risk as various portions of its cash balances are held in Canadian dollars (Cdn\$) and Colombian pesos (COP\$) while its committed capital expenditures are expected to be primarily denominated in US dollars.

The following is a summary of the foreign currency risk management contracts in place as at December 31, 2019:

Period Hedged	Reference	Currency Option Type	Amount USD	Strike Price COP
August 29, 2019 to April 30, 2020	COP	Purchased Put Option	\$10,000,000	3,200
November 13, 2019 to April 30, 2020	COP	Purchased Put Option	\$10,000,000	3,200
August 29, 2019 to June 30, 2020	COP	Purchased Put Option	\$10,000,000	3,200
November 13, 2019 to June 30, 2020	COP	Purchased Put Option	\$10,000,000	3,200

The table below summarizes the (gain) loss on the foreign currency risk management contracts that were in place during the year ended December 31, 2019 and 2018:

For the year ended December 31,	2019	2018
Premiums paid on foreign currency risk management contracts	\$ 389	\$ —
Unrealized (gain) loss on foreign currency risk management contracts	(8,591)	8,290
Realized loss on foreign currency risk management contracts	4,469	—
Total	\$ (3,733)	\$ 8,290

The fair value of the foreign currency risk management contracts is recorded in the financial statement line item "Derivative financial instruments" in the consolidated balance sheet.

The Company recorded a \$8.6 million unrealized gain and a realized \$4.9 million loss on these contracts in the year ended December 31, 2019 which is recorded in the financial statement line item "Foreign exchange loss (gain)" in the consolidated statements of comprehensive income. The Company recorded a \$8.3 million unrealized loss on these contracts in the year ended December 31, 2018 which is recorded in the financial statement line item "Foreign exchange loss (gain)" while it was previously recorded in the financial statement line item "Finance expense".

The following sensitivity show the resulting unrealized loss (gain) and impact on net income before tax for the foreign exchange risk management contracts for the respective changes in the period end foreign exchange rates at December 31, 2019:

			Impact for the year ended December 31, 2019	
			Appreciation of COP 10%	Depreciation of COP 10%
Exchange Rate USD/COP	Exchange Rate USD/COP	\$	(1,653)	511

23. Segmented Information

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

For the year ended December 31, 2019	Canada	Colombia	Total
Oil and natural gas sales	\$ —	\$ 1,113,622	\$ 1,113,622
Royalties	—	(136,068)	(136,068)
Revenue	—	977,554	977,554
Commodity risk management contracts (loss)	—	—	—
	—	977,554	977,554
Expenses			
Production	—	111,061	111,061
Transportation	—	88,974	88,974
Purchased oil	—	52,791	52,791
General and administrative	18,706	15,508	34,214
Equity settled share-based compensation expense	7,603	—	7,603
Cash settled share-based compensation expense	8,837	11,244	20,081
Depletion, depreciation and amortization	903	124,996	125,899
Foreign exchange loss (gain)	(290)	7,214	6,924
Impairment of exploration and evaluation assets	—	22,767	22,767
	35,759	434,555	470,314
Finance (income)	(4,228)	(3,154)	(7,382)
Finance expense	1,699	9,259	10,958
Net finance (income) expense	(2,529)	6,105	3,576
Income (loss) before taxes	(33,230)	536,894	503,664
Current tax expense	2,397	117,766	120,163
Deferred tax expense	5,139	50,368	55,507
Net income (loss)	\$ (40,766)	\$ 368,760	\$ 327,994
Capital assets (end of year)	\$ 1,634	\$ 964,365	\$ 965,999
Capital expenditures	\$ 121	\$ 208,075	\$ 208,196
Total assets (end of year)	\$ 151,514	\$ 1,533,067	\$ 1,684,581

For the year ended December 31, 2018	Canada		Colombia		Total
Oil and natural gas sales	\$	—	\$	965,723	\$ 965,723
Royalties		—		(132,735)	(132,735)
Revenue		—		832,988	832,988
Commodity risk management contracts (loss)		—		(795)	(795)
		—		832,193	832,193
Expenses					
Production		—		90,037	90,037
Transportation		—		57,496	57,496
Purchased oil		—		12,026	12,026
General and administrative		16,244		17,111	33,355
Equity settled share-based compensation expense		13,529		—	13,529
Cash settled share-based compensation expense		266		2,899	3,165
Depletion, depreciation and amortization		145		103,161	103,306
Foreign exchange gain		(218)		(7,195)	(7,413)
Impairment of exploration and evaluation assets		—		15,172	15,172
		29,966		290,707	320,673
Finance (income)		(10,061)		(486)	(10,547)
Finance expense		641		13,200	13,841
Net finance expense (income)		(9,420)		12,714	3,294
Income (loss) before taxes		(20,546)		528,772	508,226
Current tax expense		—		246,040	246,040
Deferred tax (recovery) expense		7,657		(148,375)	(140,718)
Net income (loss)	\$	(28,203)	\$	431,107	\$ 402,904
Capital assets (end of year)	\$	189	\$	903,142	\$ 903,331
Capital expenditures	\$	87	\$	302,256	\$ 302,343
Total assets (end of year)	\$	198,434	\$	1,443,686	\$ 1,642,120

In Colombia in the year 2019 the majority of oil sales were with ten counterparties (year ended December 31, 2018 – ten counterparties) in the oil and gas industry and are subject to normal industry credit risks.

24. Commitments and Contingencies

a) Colombia

At December 31, 2019 performance guarantees are in place with the ANH for certain blocks. The guarantees are in the form of issued letters of credit totaling \$47.9 million (December 31, 2018 - \$111.6 million) to support the exploration work commitments in respect of the 24 blocks in Colombia.

At December 31, 2019 EDC has provided the Company's bank with performance security guarantees to support approximately \$25.4 million (December 31, 2018 - \$79.7 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 are reduced from time to time to reflect completed work on an ongoing basis. At December 31, 2019, there are an additional \$22.5 million (December 31, 2018 - \$31.9 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, 2019 in respect of the Colombia blocks are estimated to be as follows:

(000s)		
2020	\$	15,370
2021		52,154
Thereafter		89,091
	\$	156,615

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, 2019 are as follows:

(000s)	Total	2020	2021	2022	2023	Thereafter
Office and accommodations	\$ 9,845	3,208	1,886	1,603	1,628	1,520

25. Related Party Disclosures**a) Significant Subsidiaries**

The consolidated financial statements include the financial statements of Parex Resources Inc. at December 31, 2019 and 2018. 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,	2019		2018	
Salaries, directors' fees and other benefits	\$	4,241	\$	4,315
Equity settled share-based compensation		3,714		5,199
Cash settled share-based compensation		4,934		860
	\$	12,889	\$	10,374

At December 31, 2019 key management personnel are comprised of the Company's directors and seven executives. As at December 31, 2019, there is a Cdn\$8.9 million commitment relating to change of control or termination of employment of the seven executives (December 31, 2018 - Cdn\$8.9 million for the seven executives).

c) Other transactions

The Company did not have any related party transactions with entities outside the consolidated group for the years ended December 31, 2019 and 2018.

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, 2019 and 2018 is dated March 10, 2020 and should be read in conjunction with the audited consolidated financial statements for the years ended December 31, 2019 and 2018. 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, including disclosure of production and sales volumes by product type, are included in reports on file with Canadian securities regulatory authorities, including the Company's Annual Information Form dated March 10, 2020 (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. 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 23 for Reserves Information, page 24 for the Advisory on Forward-Looking Statements and page 26 for Non-GAAP Terms used.

2019 Highlights

- Earned net income of \$328.0 million (\$2.24 per share basic) for the year ended December 31, 2019 as compared to a \$402.9 million net income (\$2.59 per share basic) for the year ended December 31, 2018;
- Funds flow provided by operations ("FFO") was \$570.5 million (\$3.90 per share basic), a 42% increase from the year ended December 31, 2018 of \$400.6 million (\$2.58 per share basic) not withstanding a 10% decrease in Brent reference pricing year over year;
- Free fund flow the year ended December 31, 2019 was \$362.3 million as compared to \$98.3 million for the year ended December 31, 2018;
- Utilized a portion of free funds flow of \$223.9 million to purchase 14,679,474 of the Company's common shares at an average price of Cdn \$20.41 pursuant to the Company's normal course issuer bid program ("NCIB");
- Annual oil and natural gas production in 2019 averaged 52,687 barrels of oil equivalent per day ("boe/d") (98% crude oil), an increase of 19% over 2018 average production of 44,408 boe/d or 26% on a production per basic share basis;
- Generated an operating netback of \$37.51/boe (2018 - \$41.44/boe) and FFO netback of \$29.61/boe (2018 - \$24.65/boe) from an average Brent price of \$64.21/bbl (2018 - \$71.59/bbl);
- Capital expenditures for the year ended December 31, 2019 were \$208.2 million compared to \$302.3 million for the year ended December 31, 2018. Capital expenditures were funded from FFO.
- Increased working capital to \$344.0 million at December 31, 2019 compared to a working capital position of \$218.5 million at December 31, 2018, and exited 2019 with no bank or term debt; and
- Participated in drilling 43 gross (26.95 net) wells in Colombia resulting in 38 oil wells, 1 abandoned well, 2 suspended wells and 2 wells under test, for a success rate of 97% compared to 54 gross (34.40 net) wells in the comparative period of 2018.

Three Months Ended December 31, 2019 ("fourth quarter" or "Q4") Highlights

- Earned net income of \$87.2 million (\$0.61 per share basic) compared to net income of \$54.1 million (\$0.35 per share basic) in Q4 2018;
- Generated FFO of \$143.3 million (\$1.00 per share basic) a 7% decrease compared to \$154.2 million (\$0.99 per share basic) in Q4 2018;
- For the three months ended December 31, 2019 the Company recognized free funds flow of \$84.9 million compared to \$77.5 million in Q4 2018;
- Utilized a portion of free funds flow of \$9.7 million to purchase 596,964 of the Company's common shares at an average price of Cdn\$20.35 pursuant to the Company's NCIB program;
- Achieved a record quarterly oil and natural gas production of 54,221 boe/d (98% crude oil), an increase of 10% over the fourth quarter of 2018, a 2% increase over the previous quarter ended September 30, 2019, and 3% higher than the 2019 average oil and natural gas production, or 3% and 20% on a per basic share basis, respectively;
- Fourth quarter sales volumes, excluding purchased oil, averaged 55,831 boe/d (2018 - 52,161 boe/d);
- Realized an operating netback of \$36.43/boe (2018 - \$37.89/boe) and an FFO netback of \$27.89/boe (2018 - \$32.14/boe) from an average Brent price of \$62.49/bbl (2018 - \$68.32/bbl);
- Capital expenditures were \$58.3 million in the period compared to \$76.8 million in the comparative period of 2018 and \$208.2 million for the full year in 2019. The fourth quarter capital expenditure program included \$52.7 million for drilling and completion;
- Working capital was \$344.0 million at December 31, 2019 compared to \$279.9 million at September 30, 2019 and \$218.5 million at December 31, 2018; and
- Participated in drilling 15 gross (9.25 net) wells in Colombia resulting in 11 oil wells, 1 abandoned well, 1 suspended well and 2 wells under test, for a success rate of 92% in Q4 2019 compared to 28 gross (17.70 net) wells in the preceding nine months of 2019 and 8 gross (4.30 net) wells in the fourth quarter of 2018.

Financial Summary

	For the three months ended December 31,		For the year ended December 31,		
(Financial figures in 000s except per share amounts)	2019	2018	2019	2018	2017
Average daily oil production (bbl/d)	53,086	48,559	51,708	43,788	35,212
Average daily natural gas production (mcf/d)	6,810	4,446	5,874	3,720	1,974
Average oil and natural gas production (boe/d)	54,221	49,300	52,687	44,408	35,541
Production split (% crude oil)	98	98	98	99	99
Realized sales price (/boe)	\$ 53.00	\$ 55.42	\$ 54.70	\$ 58.64	\$ 43.73
Operating netback (/boe) ⁽¹⁾	\$ 36.43	\$ 37.89	\$ 37.51	\$ 41.44	\$ 29.69
Oil and natural gas revenue	\$ 289,585	\$ 270,599	\$ 1,113,622	\$ 965,723	\$ 572,768
Funds flow provided by operations ⁽¹⁾⁽⁴⁾	\$ 143,269	\$ 154,211	\$ 570,480	\$ 400,627	\$ 288,884
Per share – basic	1.00	0.99	3.90	2.58	1.87
Per share – diluted ⁽¹⁾	0.98	0.97	3.83	2.51	1.84
Net income	\$ 87,218	\$ 54,060	\$ 327,994	\$ 402,904	\$ 155,078
Per share – basic	0.61	0.35	2.24	2.59	1.01
Per share – diluted	0.60	0.34	2.20	2.53	0.99
Capital Expenditures	\$ 58,321	\$ 76,758	\$ 208,196	\$ 302,343	\$ 212,346
Free funds flow ⁽¹⁾	\$ 84,948	\$ 77,453	\$ 362,284	\$ 98,284	\$ 76,538
Total assets (end of period)	\$ 1,684,581	\$ 1,642,120	\$ 1,684,581	\$ 1,642,120	\$ 1,085,065
Working capital surplus (end of period) ⁽²⁾	\$ 344,031	\$ 218,526	\$ 344,031	\$ 218,526	\$ 163,401
Bank debt (end of period) ⁽³⁾	\$ —	\$ —	\$ —	\$ —	\$ —
Weighted average shares outstanding (000s)					
Basic	142,967	155,403	146,380	155,417	154,209
Diluted	145,565	159,303	149,025	159,562	157,272
Outstanding shares (end of period) (000s)	143,295	155,014	143,295	155,014	154,742

(1) Non-GAAP terms. See "Non-GAAP Terms" on page 26.

(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 \$200.0 million as at December 31, 2019, \$200.0 million at December 31, 2018.

(4) In the second quarter of 2019, Parex changed the way it calculates and presents funds flow from operations. For further details refer to the "Non-GAAP Terms" on page 26. Comparative periods have also been adjusted for this change. For the year ended December 31, 2018, funds flow provided by operations includes a \$137.5 million (\$0.88

per share basic) charge for a voluntary tax restructuring, refer to the "Income Tax" section. For the year ended December 31, 2017, funds flow provided by operations includes a \$15.0 million (\$0.10 per share basic) charge for a one-time legal settlement.

Guidance

The table below is a summary of Parex' original annual guidance for 2019 and 2020, and a review of 2019 actual results:

	2020 Guidance (as released November 2019)	2019 Guidance (as released Dec 2018)	2019 Actuals	% Variance from 2019 Guidance
Brent crude average (\$/bbl)	60.00	60.00	64.21	7
Production (average for period) (boe/d)	54,500-56,250	52,000-54,000	52,687	—
Operating netback (\$/boe) ⁽¹⁾	33.50	—	37.51	—
Funds Flow provided by Operations (FFO) netback ⁽¹⁾ (\$/boe)	26.50	—	29.61	—
Total Capital Expenditures (\$ millions)	210-240	200-230	208	—
Funds Flow provided by Operations (FFO) ⁽¹⁾⁽²⁾ (\$ millions)	520-550	450-500	570	14
Free Funds Flow (FFO less Total Capex mid-points) ⁽¹⁾ (\$ millions)	—	—	362	40
Outstanding shares (end of period) ⁽³⁾ (millions)	0	—	143	—
Production per share growth %	14%	—	26%	—
Current tax effective rate on FFO (%)	17%	14-17%	17%	—

(1) The table above contains Non-GAAP measures. See "Non-GAAP Terms" on page 26.

(2) 2020 Guidance assumes Brent/Vasconia crude differential less than \$3/bbl.

(3) It is expected free funds flow will be used to fund the 2020 share buy-back program. Outstanding shares at Dec 31, 2020 assumes 1 million shares of equity settled long term compensation exercised in the period.

Parex's 2019 financial and operational results were above or within guidance. Actual 2019 funds flow provided by operations and free funds flow exceeded guidance mainly related to higher Brent benchmark pricing and stronger Vasconia pricing. Refer to Colombian Oil and Natural Gas sales section below for further information.

The Company expects Q1 2020 average production to average approximately 54,500 boe/d.

Balance Sheet Strength and Resiliency provides Optionality

In light of the recent decrease in world crude oil prices, the table below summarizes the operational sensitivities on Parex' 2020 guidance:

Brent crude average (\$/bbl) (March - December 2020)	30.00	40.00	50.00
Production (average for period) (boe/d)	54,500	54,500	54,500
Operating netback (\$/boe) ⁽¹⁾	12.00	19.00	26.00
Funds Flow provided by Operations (FFO) netback ⁽¹⁾ (\$/boe)	10.00	15.00	20.00
2020 Total Capital Expenditures (\$ millions) ⁽⁴⁾	160	175	230
2020 Funds Flow provided by Operations (FFO) ⁽¹⁾⁽²⁾⁽⁴⁾ (\$ millions)	190	295	410
2020 Free Funds Flow (FFO less Total Capex) ⁽¹⁾⁽⁴⁾ (\$ millions)	30	120	180
Outstanding shares (end of period) ⁽³⁾ (millions)	130	130	130
2020 Current tax effective rate on FFO (%)	4%	12%	14%

(1) The table above contains Non-GAAP measures. See "Non-GAAP Terms" on page 26.

(2) Assumes Brent/Vasconia crude differential of \$5/bbl.

(3) It is expected free funds flow will be used to fund the 2020 share buy-back program. Outstanding shares at Dec 31, 2020 assumes 1 million shares of equity settled long term compensation exercised in the period.

(4) 2020 total capital, funds flow from operations, and free funds flow include January and February actuals at an average Brent crude price of \$60/bbl for the first 2 months of 2020. At low oil prices, capital will be focused on maintenance and development (LLA-34 & Cabrestero) and growth in Capachos and VIM-1.

Parex is in a strong position, as even in a lower oil price environment the Company expects to purchase the maximum number of shares under its NCIB and fund its planned capital expenditures with funds flow from operations, and if appropriate potentially utilizing a portion of cash reserves.

Financial and Operational Results

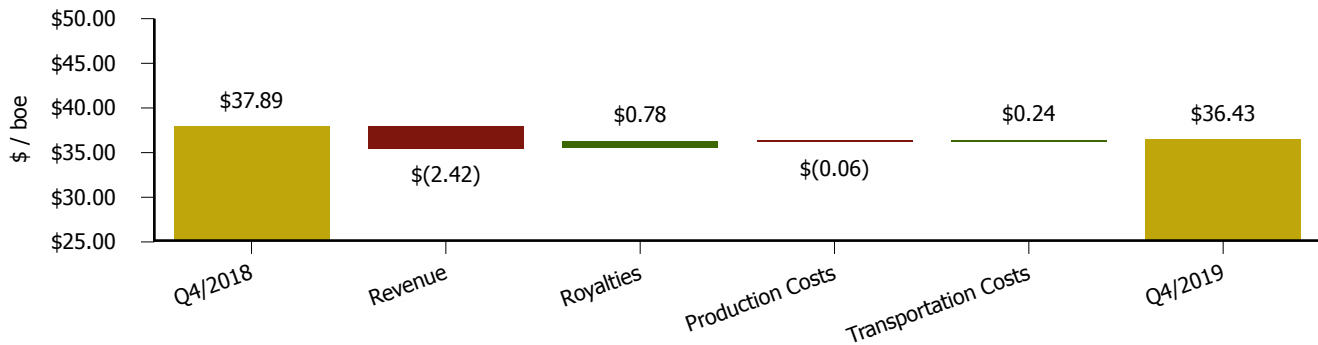
Consolidated Results of Operations

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,	
	2019	2018	2019	2018
Average daily production				
Crude oil (bbl/d)	53,086	48,559	51,708	43,788
Natural gas (mcf/d)	6,810	4,446	5,874	3,720
Total (boe/d)	54,221	49,300	52,687	44,408
<hr/>				
Production split (% crude oil production)	98	98	98	99
<hr/>				
Average daily sales of oil and natural gas				
Produced crude oil (bbl/d)	54,696	51,420	51,799	43,903
Purchased crude oil (bbl/d)	3,561	909	2,991	596
Produced natural gas (mcf/d)	6,810	4,446	5,874	3,720
Total (boe/d)	59,392	53,070	55,769	45,119
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Operating netback (000s) ⁽¹⁾				
Oil and natural gas sales excluding risk management contracts	\$ 289,585	\$ 270,599	\$ 1,113,622	\$ 965,723
Royalties	(36,717)	(38,068)	(136,068)	(132,735)
Net revenue	252,868	232,531	977,554	832,988
Production expense	(29,183)	(26,966)	(111,061)	(90,037)
Transportation expense	(20,462)	(19,442)	(88,974)	(57,496)
Purchased oil expense	(16,154)	(3,951)	(52,791)	(12,026)
Operating netback	\$ 187,069	\$ 182,172	\$ 724,728	\$ 673,429
<hr/>				
Operating netback (per boe) ⁽¹⁾				
Oil and natural gas sales	\$ 53.00	\$ 55.42	\$ 54.70	\$ 58.64
Royalties	(7.15)	(7.93)	(7.06)	(8.17)
Net revenue	45.85	47.49	47.64	50.47
Production expense	(5.68)	(5.62)	(5.76)	(5.54)
Transportation expense	(3.74)	(3.98)	(4.37)	(3.49)
Operating netback	\$ 36.43	\$ 37.89	\$ 37.51	\$ 41.44

(1) Refer to page 26 "Non-GAAP Terms" for a description and details of the operating netback calculation.

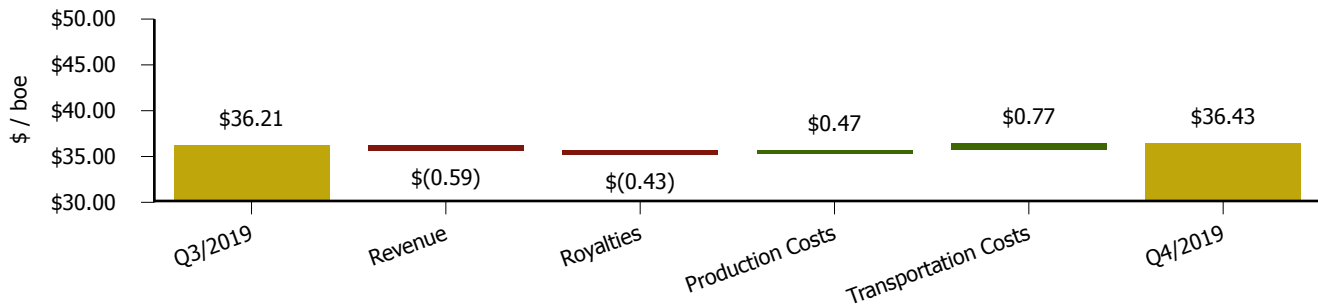
**Change in Operating Netback by Component
Q4/18 vs. Q4/19**



Overall, the Company's benchmark Brent price decreased by \$5.83/bbl, while revenue decreased \$2.42/boe in the fourth quarter of 2019 as compared to the fourth quarter of 2018. The price improvement relative to the Brent crude benchmark decrease is mainly a result of stronger Vasconia pricing and a decrease in wellhead sales as compared to the comparative period. On a relative basis, transportation expense decreased \$0.24/boe mainly as a result of the depreciation of the Colombian peso, as truck transportation costs are denominated in Colombian pesos. Royalties also decreased by \$0.78/boe as a result of lower crude prices in the quarter.

Overall, the operating netback decreased by \$1.46/boe vs a Brent benchmark crude decrease of \$5.83/bbl.

**Change in Operating Netback by Component
Q3/19 vs. Q4/19**



Overall, the Company's benchmark Brent price increased by \$0.46/bbl, while revenue decreased \$0.59/boe in the fourth quarter of 2019 as compared to the third quarter of 2019. The minor price decrease relative to the Brent crude benchmark increase is mainly a result of lower Vasconia pricing as compared to the comparative period. On a relative basis, transportation expense decreased \$0.77/boe mainly as a result of the depreciation of the Colombian peso and lower negotiated transportation costs. Royalties increased by \$0.43/boe as a result of higher crude oil benchmark prices. Production costs decreased by \$0.47/boe related to lower workovers on Block LLA-34 compared to the comparative period.

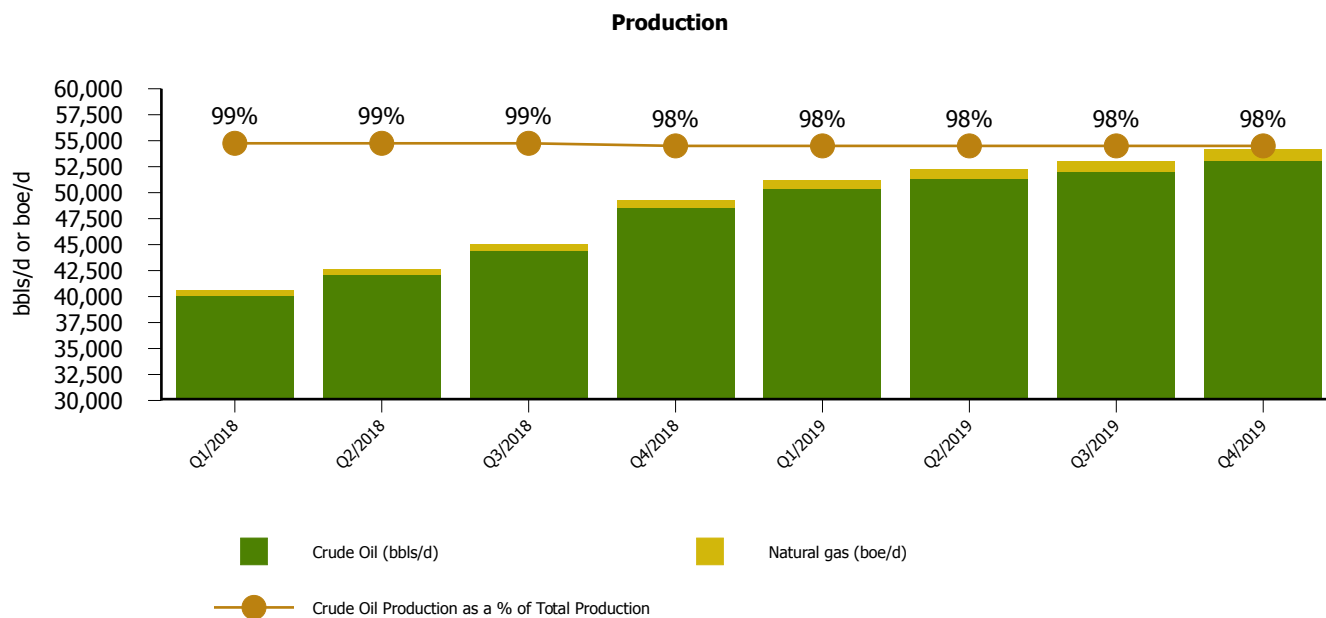
Overall, the operating netback increased by \$0.22/boe vs a Brent benchmark crude increase of \$0.46/bbl.

Colombian Oil and Natural gas Sales

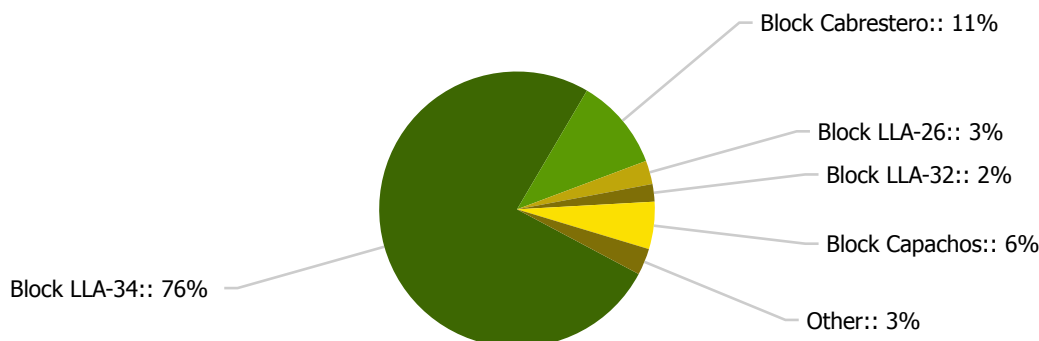
a) Average Daily Production and Sales Volumes (boe/d)

	For the three months ended December 31,		For the year ended December 31,	
	2019	2018	2019	2018
Block LLA-34 (Tigana, Jacana, Tua, Tarotaro and Tilo fields)	40,186	35,922	38,549	33,267
Block Cabrestero (Bacano, Akira and Kitara fields)	5,739	7,914	6,032	5,497
Capachos block (Capachos and Andina fields)	2,947	774	2,440	534
Block LLA-26 (Rumba field)	1,468	1,013	1,626	1,770
Block LLA-32 (Kananaskis, Calona, Carmentea and Azogue fields)	1,093	1,323	1,389	1,281
Other blocks	1,653	1,613	1,672	1,439
Total Crude Oil Production	53,086	48,559	51,708	43,788
Natural gas production	1,135	741	979	620
Total crude oil and natural gas production	54,221	49,300	52,687	44,408
Crude oil inventory draw (build)	1,610	2,861	91	115
Average daily sales of produced oil and natural gas	55,831	52,161	52,778	44,523
Purchased oil	3,561	909	2,991	596
Sales Volumes	59,392	53,070	55,769	45,119

Oil and natural gas production for the fourth quarter of 2019 averaged 54,221 boe/d, an increase of approximately 2% from the third quarter of 2019 and a 10% increase from the fourth quarter of 2018. The increase in sales volumes in the fourth quarter of 2019 compared to the fourth quarter of 2018 is a result of increased production and Parex' crude oil inventory returning to historical levels as crude sales were greater than crude oil production in the fourth quarter of 2019. The Cabrestero block production decline in fourth quarter of 2019 compared to the fourth quarter of 2018 is a result of the Company managing production to meet guidance.



**Production By Area
(Three Months ended December 31, 2019)**



b) Crude Oil Reference and Realized Prices

	For the three months ended December 31,		For the year ended December 31,	
	2019	2018	2019	2018
Reference Prices				
Brent (\$/bbl)	62.49	68.32	64.21	71.59
Vasconia (\$/bbl)	58.50	63.06	60.89	66.65
WTI (\$/bbl)	56.94	58.99	57.05	64.86
Average Realized Prices				
Realized sales price (\$/boe)	53.00	55.42	54.70	58.64
Realized commodity risk management (loss) (\$/boe)	—	—	—	(0.06)
Realized sales price after commodity risk management (loss) (\$/boe)	53.00	55.42	54.70	58.58
Realized price (differential) to Brent crude (\$/boe)	(9.49)	(12.90)	(9.51)	(12.95)

During Q4 2019, the differential between Brent reference pricing and the Company's realized sale price was \$9.49/boe. The differential to Brent crude during Q4 increased by \$1.05/boe compared to the third quarter of 2019 where the differential was \$8.44/boe (see below).

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

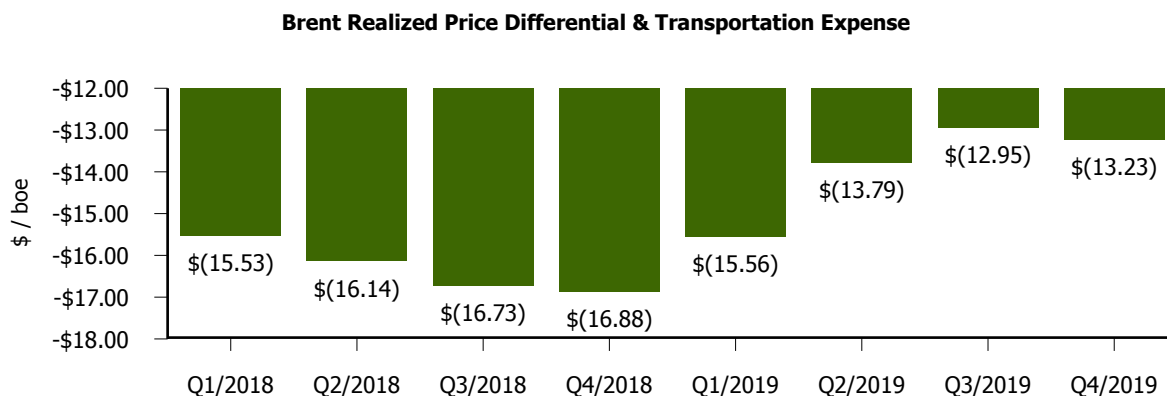
Average price for the period	Q4 2019	Q3 2019	Q2 2019	Q1 2019	Q4 2018
Brent (\$/bbl)	62.49	62.03	68.52	63.83	68.32
Vasconia (\$/bbl)	58.50	59.18	65.60	60.34	63.06
Brent/Vasconia crude (differential) (\$/bbl)	(3.99)	(2.85)	(2.92)	(3.49)	(5.26)
Parex quality differential (\$/bbl)	(0.72)	(0.38)	(0.19)	(0.06)	(0.13)
Parex wellhead sales discount (\$/bbl)	(4.78)	(5.21)	(5.49)	(7.95)	(7.51)
Parex realized sales price (\$/boe)	53.00	53.59	59.92	52.33	55.42
Parex realized price (differential) to Brent crude (\$/boe)	(9.49)	(8.44)	(8.60)	(11.50)	(12.90)
Parex transportation expense (\$/boe) ⁽¹⁾	(3.74)	(4.51)	(5.19)	(4.06)	(3.98)
Parex price differential and transportation expense (\$/boe)	(13.23)	(12.95)	(13.79)	(15.56)	(16.88)

(1) See Transportation section below.

Differences between Parex' realized price and Vasconia crude price is mainly related to quality adjustments, wellhead sale marketing contracts, 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 recent dramatic fall in world crude prices could widen the Brent/Vasconia differential going forward given potential heavy crude production increases from the middle east.

Parex realized price differential to Brent and Vasconia crudes can fluctuate period over period due to, among other factors, the type of sales contracts and the accounting treatment for a contract sold at the wellhead, versus a direct export sales contract.

The combined price differential and transportation expense has trended downward due to the shrinking of Vasconia crude differential and the depreciation of the Colombian peso, however in the fourth quarter of 2019 this differential widened by approximately \$1.14/boe compared to the third quarter, however the total price differential plus transportation expense only changed by \$0.28/boe mainly as a result of lower transportation expense in the fourth quarter.



The Brent realized price differential plus transportation expense has decreased from \$16.88/boe in Q4 2018, to \$13.23/boe for the fourth quarter of 2019.

c) Natural Gas Revenue and Realized Prices

	For the three months ended December 31,		For the year ended December 31,	
	2019	2018	2019	2018
Natural gas revenue (\$000s)	\$ 3,361	2,755	\$12,562	9,492
Realized sales price (\$/Mcf)	5.36	6.74	5.86	6.97

Parex natural gas revenues were \$3.4 million and \$12.6 million for the three months and year ended 2019 compared to the prior year 2018 of \$2.8 million and \$9.5 million. The increase in natural gas sales from the prior periods is related to increased natural gas volumes sold from Block LLA-32 and the Capachos block.

d) Oil and Natural Gas Revenue

2019 oil and natural gas revenue increased by \$147.9 million or 15% as reconciled in the table below to 2018:

(\$000s)	
Oil and natural gas revenue, year ended December 31, 2018	\$ 965,723
Sales volume of produced oil, an increase of 18% (7,896 bbl/d)	169,753
Sales volume of purchased oil, an increase of 402% (2,395 bbl/d)	51,455
Sales price decrease of 6%	(76,379)
Sales volume and price change of produced natural gas, an increase of 58% (359 boe/d)	3,070
Oil and natural gas revenue, year ended December 31, 2019	\$ 1,113,622

Oil and natural gas revenue increased year over year mainly due to the increased sales volumes of produced and purchased oil, partially offset by the decrease in world oil prices.

e) Colombian Crude Oil Inventory in Transit

(\$000s)		2019	2018
For the years ended December 31,			
Crude oil in transit		\$ 653	\$ 1,446

At December 31, 2019, the Company had 27,653 bbls (December 31, 2018 - 60,977 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 \$24/bbl (\$24/bbl - 2018) incurred in bringing the crude oil to its existing condition and location.

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

(mmbbls) For the periods ended	Dec. 31, 2019	Sep. 30, 2019	June 30, 2019	Mar. 31, 2019
Crude oil inventory in transit - beginning	175.8	116.6	91.0	61.0
Oil production	4,885.2	4,783.6	4,673.2	4,534.0
Oil sales	(5,360.9)	(5,047.6)	(4,954.4)	(4,637.9)
Purchased oil	327.6	323.2	306.8	133.9
Crude oil inventory in transit - end	27.7	175.8	116.6	91.0
% of period production	0.6	3.7	2.5	2.0

Crude oil inventory build and (draw) 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, 2019 was 0.6%. Parex expects crude oil inventory in future periods to be in line with normal historic levels of below 3% of period production.

f) Purchased Oil

	For the three months ended December 31,		For the year ended December 31,	
	2019	2018	2019	2018
Purchased oil expense (\$000s)	\$ 16,154	\$ 3,951	\$ 52,791	\$ 12,026

Purchased oil expense for the three months and year ended December 31, 2019 was \$16.2 million and \$52.8 million as compared to \$15.4 million in the preceding quarter and \$4.0 million and \$12.0 million for the three months and year ended December 31, 2018. Purchased oil expense has increased as a result of an increase in oil blending operations and the purchase of partner crude at certain fields, primarily at the Capachos field. Transportation costs are incurred by the Company to transport purchased oil to sale delivery points.

Colombian Royalties

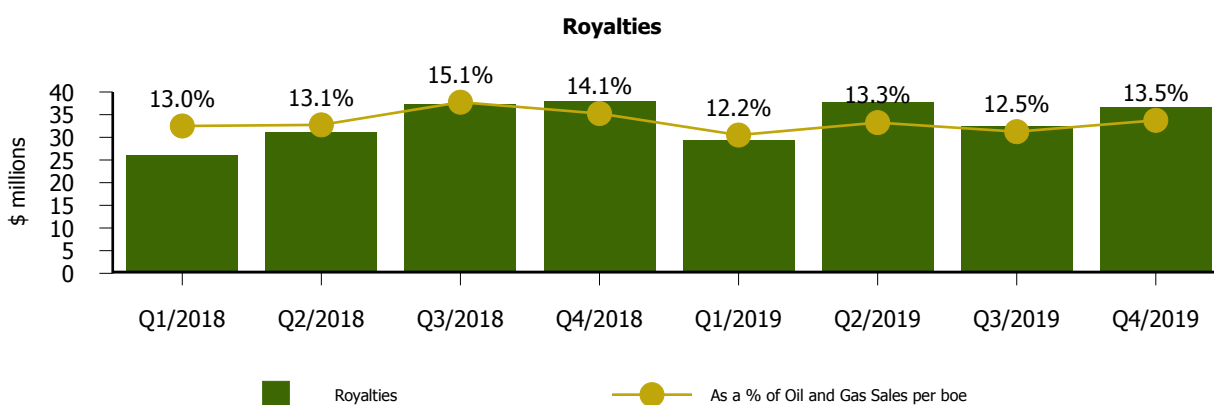
	For the three months ended December 31,		For the year ended December 31,	
	2019	2018	2019	2018
Royalties (\$000s)	\$ 36,717	\$ 38,068	\$ 136,068	\$ 132,735
Per unit (\$/boe) ⁽¹⁾	7.15	7.93	7.06	8.17
Percentage of sales ⁽¹⁾	13.5	14.1	12.9	14.0

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

For the three months and year ended December 31, 2019 royalties as a percentage of sales was 13.5% and 12.9%, a decrease from 14.1% and 14.0% in the three months and year ended December 31, 2018. The third quarter of 2019 royalty as a percentage of sales was 12.5%. The decrease in royalties as a percentage of oil sales compared to the prior year is a result of lower benchmark WTI prices which are used in the HPR calculation, somewhat offset by increased production from fields where the high price share royalty ("HPR") is applicable. Benchmark WTI prices for the three months and year ended December 31, 2019 were \$56.94 and \$57.05 compared to \$56.41 in the third quarter of 2019, and \$58.99 and \$64.86 for the 2018 comparative periods.

The decrease in royalty expense to \$36.7 million in the three months ended December 31, 2019 compared to \$38.1 million for the 2018 comparative prior year period is a result of lower benchmark WTI prices, partially offset by increased oil production and sales over the prior period. The increase in royalty expense to \$136.1 million year to date compared to \$132.7 million in the comparative prior year period is a result of increased oil production and sales over the prior period, partially offset by lower benchmark WTI prices used in the royalty calculation.

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,	
	2019	2018	2019	2018
Production expense (\$000s)	\$ 29,183	\$ 26,966	\$ 111,061	\$ 90,037
Per unit (\$/boe) ⁽¹⁾	5.68	5.62	5.76	5.54

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,	
	2019	2018	2019	2018
Per unit (\$/boe) – based on sales volumes – operated ⁽¹⁾	8.88	10.17	8.66	9.26
Per unit (\$/boe) – based on sales volumes – non-operated ⁽¹⁾	4.45	3.58	4.68	4.22

(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.

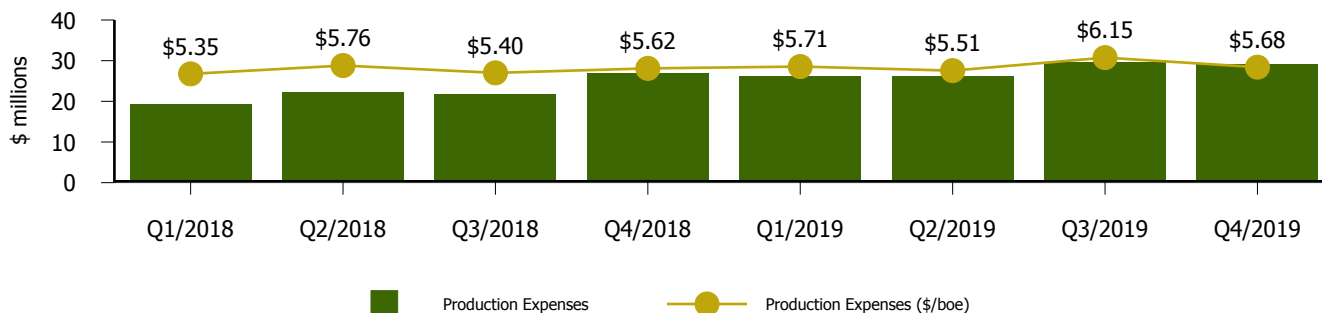
Production expense for the three months and year ended December 31, 2019 was \$5.68/boe and \$5.76/boe compared to \$5.62/boe and \$5.54/boe for the three months and year ended December 31, 2018. Production expense for the third quarter of 2019 was \$6.15/boe.

Operated properties production expense in the fourth quarter of 2019 was \$8.88/boe compared to \$8.05/boe for the third quarter of 2019 and non-operated properties production expense was \$4.45/boe for the fourth quarter of 2019 compared to \$5.40/boe for the third quarter of 2019. The quarter over quarter increase in the operated properties production expense relates to an increase in well services performed on operated blocks and additional production added at higher cost fields. The quarter over quarter decrease in the non-operated properties production expense relates to a reduction in the amount of workovers completed in the current quarter on Block LLA-34.

The increase in non-operated production expense for the year ended December 31, 2019 over the 2018 comparative period is a result of increased well workovers on Block LLA-34.

The primary reason for the decrease in operated production expense for the year ended December 31, 2019 is a result of less well workovers in 2019 and additional production in Q4 2019 from the Capachos field compared to the prior period.

Production Expense



Colombian Transportation Expense

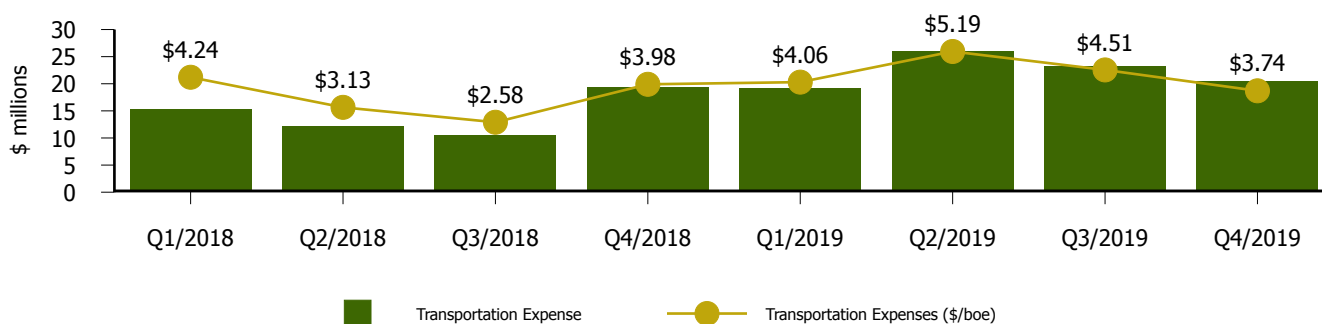
	For the three months ended December 31,		For the year ended December 31,	
	2019	2018	2019	2018
Transportation expense (\$000s)	\$ 20,462	\$ 19,442	\$ 88,974	\$ 57,496
Per unit (\$/boe)	3.74	3.98	4.37	3.49

Transportation expense includes trucking costs incurred to transport production to several offloading stations for sale and in some instances an oil transportation tariff from delivery point to the buyer's facility and pipeline tariffs.

For the three months ended December 31, 2019, the cost of transportation of \$3.74/boe has decreased compared to the third quarter of 2019 cost of \$4.51/boe and decreased from the comparative period in 2018 of \$3.98/boe. The slight decrease from the comparative prior year period is mainly a result of a higher percentage of oil sales being sold at the wellhead for which no transportation costs are paid by Parex and the depreciation of the Colombian peso. Accordingly, transportation expense will fluctuate period over period due the mix of sales contracts types in force during the period. The decrease from the third quarter of 2019 is mainly due to the depreciation of the Colombian peso.

On a year to date basis transportation expense has increased to \$4.37/boe from \$3.49/boe in the comparative period in 2018. However, looking at the combined transportation expense and price differential off Brent on a per boe basis, this amount has trended down from the prior year. See "Crude Oil Reference and Realized Prices" on page 8.

Transportation Expenses



General and Administrative Expense ("G&A")

(\$000s)	For the three months ended December 31,		For the year ended December 31,	
	2019	2018	2019	2018
Gross G&A	\$ 13,227	\$ 11,329	\$ 46,067	\$ 44,648
G&A recoveries	(496)	(749)	(1,649)	(1,843)
Capitalized G&A	(1,820)	(2,629)	(10,204)	(9,450)
Net G&A expense	\$ 10,911	\$ 7,951	\$ 34,214	\$ 33,355
Per unit (\$/boe) ⁽¹⁾	2.19	1.75	1.78	2.06

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

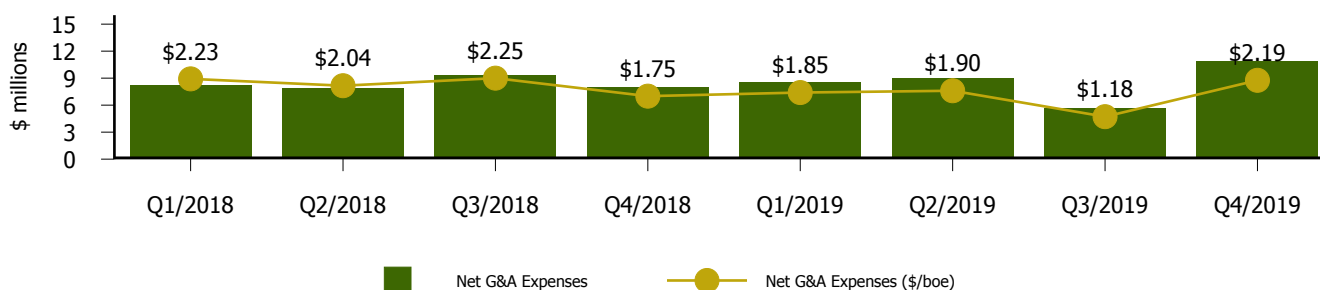
Net G&A was \$10.9 million and \$34.2 million for the three months and year ended December 31, 2019 compared to \$8.0 million and \$33.4 million for the same periods in 2018. Gross G&A was \$13.2 million and \$46.1 million for the three months and year ended December 31, 2019 (three months and year ended December 31, 2018 - \$11.3 million and \$44.6 million). On a units of production basis net G&A for the year has decreased 14% from the comparative year.

The increase of gross G&A on both a quarter and year to date basis is mainly a result of general G&A increases, partially offset by the depreciation of the Colombian peso.

Also, included in G&A expense in the year ended December 31, 2019 is a one-time donation of \$2.0 million to the University of Calgary to support innovation fellowships in the faculty of science. The donation was in recognition of our 10 year anniversary, and commitment to community advancement and support in our areas of operation. Parex also made a donation of \$0.3 million to a Colombian hospital burn unit in 2019 and plans to donate an additional \$1.3 million to this same cause in the first half of 2020.

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 14 to see the affects of foreign exchange sensitivities on net G&A per boe.

Net General and Administrative Expenses



Share-Based Compensation

(\$000s)	For the three months ended December 31,		For the year ended December 31,	
	2019	2018	2019	2018
Equity settled share-based compensation expense	\$ 1,785	\$ 2,925	\$ 7,603	\$ 13,529
Cash settled share-based compensation expense (recovery)	8,202	(6,842)	20,081	3,165
Total net expense (recovery)	\$ 9,987	\$ (3,917)	\$ 27,684	\$ 16,694

Share-based compensation expense was \$27.7 million for the year ended December 31, 2019 compared to \$16.7 million for the same period in 2018. The increase is primarily due to the increase in cash settled share-based compensation expense as explained below.

Equity settled share-based compensation expense was \$1.8 million and \$7.6 million for the three months and year ended December 31, 2019 compared to \$2.9 million and \$13.5 million for the same periods in 2018. 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") were awarded. The decrease in the equity settled plan expense from the prior year is mainly related to a significant decrease in the issuance of equity settled compensation (options, RSUs, and PSUs, as applicable) under these plans in 2019 as compared to the prior year.

Cash settled share-based compensation relates to the Company's cash settled incentive plans and includes share appreciation rights ("SARs"), cash settled restricted share units ("CRSUs"), cash or share settled restricted share units ("CosRSUs"), cash or share settled performance share units ("CosPSUs") and deferred share units ("DSUs"). The CRSU plan will replace the current SAR plan for the Colombian employees as granted SAR's vest, and are exercised. There will be no SAR grants going forward. For the three months and year ended December 31, 2019 there was an expense of \$8.2 million and \$20.1 million related to cash settled incentive plans compared to a \$6.8 million recovery and expense of \$3.2 million for the same periods in 2018. The increase in expense in 2019 relates to the issuance of CosRSUs and CosPSUs under the new cash settled plan and a change in share price. 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 16 - Cash Settled Incentive Plans of the consolidated financial statements for the year ended December 31, 2019. As at December 31, 2019, the total cash settled incentive plans liability accrued is \$27.9 million (December 31, 2018 - \$14.1 million).

Cash payments to settle cash settled share-based compensation in the three months and year ended December 31, 2019 was \$0.6 million and \$9.2 million respectively (three months and year ended December 31, 2018 - \$0.2 million and \$7.3 million).

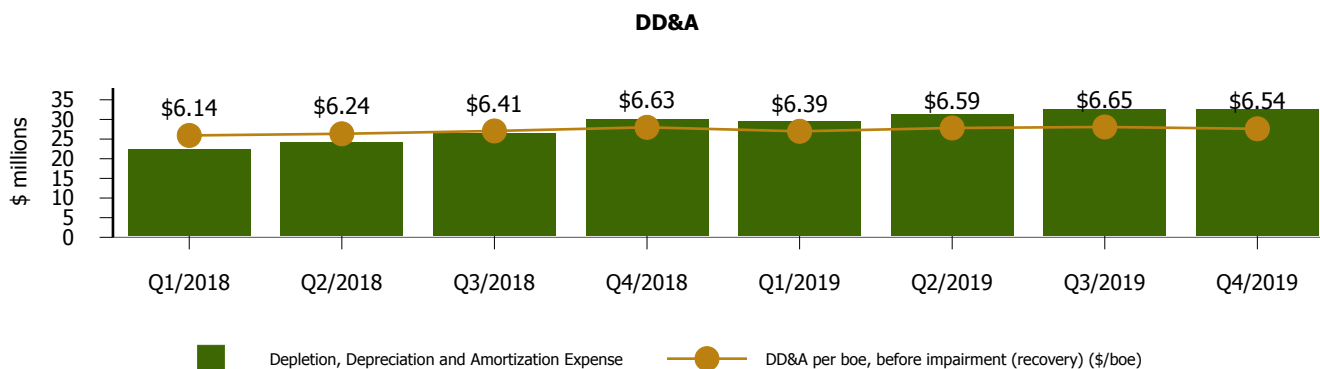
Depletion, Depreciation and Amortization Expense ("DD&A")

	For the three months ended December 31,		For the year ended December 31,	
	2019	2018	2019	2018
DD&A (\$000s) total	\$ 32,636	\$ 30,088	\$ 125,899	\$ 103,306
Per unit (\$/boe) ⁽¹⁾	6.54	6.63	6.55	6.37

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

Fourth quarter 2019 DD&A was \$32.6 million (\$6.54/boe) compared to \$30.1 million (\$6.63/boe) for the same period in 2018. For the year ended December 31, 2019 DD&A was \$125.9 million (\$6.55/boe) as compared to \$103.3 million (\$6.37/boe) for the prior year.

For the fourth quarter of 2019, future development costs of \$453.1 million (three months ended December 31, 2018 - \$411.7 million) were included in the depletion calculation. Fourth quarter 2019 DD&A of \$6.54/boe decreased from the comparative period of \$6.63/boe. The small decrease is due to the increase in proved and probable reserves, offset by an increase in oil and gas production as well as a change in the CGU production mix from the prior comparative period.



Foreign Exchange

(\$000s)	For the three months ended December 31,		For the year ended December 31,	
	2019	2018	2019	2018
Foreign exchange loss (gain) (\$000s)	\$ 5,733	\$ (19,989)	\$ 10,657	\$ (15,703)
Foreign currency risk management contracts (gain) loss	(245)	5,744	(3,733)	8,290
Total foreign exchange loss (gain)	\$ 5,488	\$ (14,245)	\$ 6,924	\$ (7,413)
Foreign Exchange Rates				
USD\$/CAD ⁽¹⁾	1.32	1.32	1.33	1.30
USD\$/Colombian peso ⁽¹⁾	3,404	3,165	3,281	2,956

(1) Average exchange rates for the period.

The Company's main exposure to foreign currency risk relates to the pricing of foreign currency denominated in Canadian dollars and Colombian pesos ("COP"), 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 is the COP denominated tax withholdings receivable and income tax payable balances in Colombia. The timing of payment settlements, accruals and their adjustments have impacts on foreign exchange gains/losses.

The Company has foreign currency gains and losses offset by foreign exchange risk management gains and loss. The foreign currency derivative contracts in place manage the foreign currency risk of the tax payable obligation that is denominated in COP. See "Risk Management".

For the three months and year ended December 31, 2019, a total foreign exchange loss of \$5.5 million and \$6.9 million was recorded compared to gains of \$14.2 million and \$7.4 million in the respective prior year periods. 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.

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

Foreign Exchange Sensitivity Analysis

Cost component	Estimated percent of cost denominated in local currency	\$/boe Impact of change in local currency/ \$USD exchange rate	
		10% appreciation of local currency	10% depreciation of local currency
Production expense	80%	\$ 0.44	\$ (0.44)
Transportation expense	50%	\$ 0.17	\$ (0.17)
G&A expense	100%	\$ 0.21	\$ (0.21)

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 2019 per boe costs. This analysis ignores all other factors impacting cost structure including efficiencies, cost reduction strategies, etc.

Net Finance Expense

	For the three months ended December 31,		For the year ended December 31,	
	2019	2018	2019	2018
Bank charges and credit facility fees	\$ 784	\$ 640	\$ 3,647	\$ 2,426
Accretion on decommissioning and environmental liabilities	1,269	1,470	4,592	4,888
Interest and other income	(1,062)	(1,719)	(7,382)	(10,547)
Right of use asset interest	22	—	99	—
Loss (gain) on settlement of decommissioning liabilities	(1,301)	1,505	359	5,531
Loss on disposition of tangible assets	3	996	235	996
Other	1,983	—	2,026	—
Net finance expense	\$ 1,698	\$ 2,892	\$ 3,576	\$ 3,294

	For the three months ended December 31,		For the year ended December 31,	
	2019	2018	2019	2018
Non-cash finance expense	\$ 1,954	\$ 3,971	\$ 7,212	\$ 11,415
Cash finance (income)	(256)	(1,079)	(3,636)	(8,121)
Net finance expense	\$ 1,698	\$ 2,892	\$ 3,576	\$ 3,294

Bank charges and credit facility fees include bank taxes paid in Colombia and the standby fees related to the undrawn credit facility. The non-cash components of net finance (income) expense include the accretion on decommissioning and environmental liabilities, loss (gain) on settlement of decommissioning liabilities, loss on disposition of tangible asset, right of use asset interest and other.

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.

a) Risk Management Contracts – Brent Crude

At December 31, 2019 the Company had no crude oil risk management contracts in place. Parex has no outstanding draw on its credit facility or significant commitments due in the next 12 months and as such it is considered appropriate not to have any commodity derivative contracts in place at this time and thereby avoid the costs associated with these types of contracts.

The table below summarizes the loss on the commodity risk management contracts that were in place during the three months and years ended December 31, 2019 and 2018:

(\$000s)	For the three months ended December 31,		For the year ended December 31,	
	2019	2018	2019	2018
Premiums paid on commodity risk management contracts	—	—	—	912
Unrealized (gain) on commodity risk management contracts	—	—	—	(117)
Total	\$ —	\$ —	\$ —	\$ 795

The Company's net unrealized commodity price derivative gain on risk management contracts for the year ended December 31, 2018 was \$0.1 million. The realized loss on commodity risk management contracts including premiums paid was \$0.9 million for the year ended December 31, 2018. The Company has no commodity risk management contracts in place for 2020.

b) Risk Management Contracts – Foreign Exchange

The Company is exposed to foreign currency risk as various portions of its cash balances are held in Colombian pesos (COP) and Canadian dollars (Cdn\$) while its committed capital expenditures are primarily denominated in US dollars.

The following is a summary of the foreign currency risk management contracts in place as at December 31, 2019:

Period Hedged	Reference	Currency Option Type	Amount USD	Strike Price COP
August 29, 2019 to April 30, 2020	COP	Purchased Put Option	\$10,000,000	3,200
November 13, 2019 to April 30, 2020	COP	Purchased Put Option	\$10,000,000	3,200
August 29, 2019 to June 30, 2020	COP	Purchased Put Option	\$10,000,000	3,200
November 13, 2019 to June 30, 2020	COP	Purchased Put Option	\$10,000,000	3,200

The table below summarizes the (gain) loss on the foreign currency risk management contracts that were in place during the three months and years ended December 31, 2019 and 2018:

(\$000s)	For the three months ended December 31,		For the year ended December 31,	
	2019	2018	2019	2018
Premiums paid on foreign currency risk management contracts	\$ 178	\$ —	\$ 389	\$ —
Unrealized (gain) loss on foreign currency risk management contracts	\$ (213)	\$ 5,744	\$ (8,591)	\$ 8,290
Realized loss (gain) on foreign currency risk management contracts	(210)	—	4,469	—
Total	\$ (245)	\$ 5,744	\$ (3,733)	\$ 8,290

The fair value of the foreign currency risk management contracts is recorded in the financial statement line item "Derivative financial instruments" in the consolidated balance sheet. Parex has in place foreign currency derivative contracts to manage foreign currency risk of its tax payable obligation that is denominated in COP.

For the three months and year ended December 31, 2019, the Company recorded a \$0.2 million and \$3.7 million gain on foreign currency risk management contracts compared to a \$5.7 million and \$8.3 million loss in the comparative periods in 2018, which are recorded in the financial statement line item "Foreign exchange loss (gain)" in the consolidated statements of comprehensive income while it was previously recorded in the financial statement line item "Finance expense" in 2018.

Income Tax

The components of tax expense for the three and twelve months ended December 31, 2019 and 2018 were as follows:

(\$000s)	For the three months ended December 31,		For the year ended December 31,	
	2019	2018	2019	2018
Current tax expense	\$ 32,763	\$ 21,689	\$ 120,163	\$ 246,040
Deferred tax (recovery)	(10,855)	68,482	55,507	(140,718)
Total tax expense	\$ 21,908	\$ 90,171	\$ 175,670	\$ 105,322

Current tax expense in the fourth quarter of 2019 was \$32.8 million as compared to \$21.7 million in the comparative three month period. In the current quarter tax expense as a percentage of consolidated cash flows before tax was 18.6%. For the full year 2019 the Company recorded \$120.2 million of current tax expense as compared to \$246.0 million in 2018. This decrease primarily relates to the tax restructuring completed in Q2 2018 which added approximately \$137.5 million of current tax in 2018.

Deferred tax in the fourth quarter of 2019 was a recovery of \$10.9 million and an expense of \$55.5 million for the year ended December 31, 2019 (\$68.5 million expense and \$140.7 million recovery for the three months and year ended December 31, 2018). The deferred tax recovery in the quarter is a result of the appreciation of the Colombian peso at the period end date compared to the prior year and its effect on the Colombian tax basis, offset somewhat by the unwinding of the deferred tax asset related to the tax restructuring completed in Q2 2018.

For the full year 2019 Parex recorded a deferred tax expense of \$55.5 million. The main driver of this expense is the unwinding of the tax asset created as a result of the tax restructuring completed in Q2 2018.

Capital Expenditures and Acquisitions

(\$000s) For the year ended December 31,	Colombia		Canada		Total	
	2019	2018	2019	2018	2019	2018
Acquisition of unproved properties	\$ 1,476	\$ 17,611	\$ —	\$ —	\$ 1,476	\$ 17,611
Geological and geophysical	12,366	8,647	—	—	12,366	8,647
Drilling and completion	175,502	235,336	—	—	175,502	235,336
Well equipment and facilities	18,600	40,484	—	—	18,600	40,484
Other	130	178	122	87	252	265
Total capital expenditures and acquisitions	\$ 208,074	\$ 302,256	\$ 122	\$ 87	\$ 208,196	\$ 302,343

(\$000s) For the three months ended December 31,	Colombia		Canada		Total	
	2019	2018	2019	2018	2019	2018
Acquisition of unproved properties	\$ 52	\$ 17,086	\$ —	\$ —	\$ 52	\$ 17,086
Geological and geophysical	4,349	672	—	—	4,349	672
Drilling and completion	52,676	43,415	—	—	52,676	43,415
Well equipment and facilities	1,126	16,067	—	—	1,126	16,067
Other	75	(482)	43	—	118	(482)
Total capital expenditures and acquisitions	\$ 58,278	\$ 76,758	\$ 43	\$ —	\$ 58,321	\$ 76,758

Capital Expenditures Summary

During the year ended December 31, 2019 the Company incurred \$208.2 million of capital expenditures compared to \$302.3 million in the same period of 2018. During 2019 the Company drilled 43 wells (26.95 net), compared to 54 wells (34.40 net) in 2018.

During the year ended December 31, 2019 capital expenditures of \$208.2 million were self funded from funds flow from operations of \$570.5 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 2019 the Company drilled 15 gross (9.25 net) wells in Colombia compared to 8 gross (4.30 net) wells in the comparative period. Drilling and completion costs during the fourth quarter of 2019 totaled \$52.7 million, all of which related to drilling and completion and capitalized workover costs in Colombia at Blocks LLA-34, LLA-32, Cabretero and Boranda. In the fourth quarter, Parex received investment tax credits of \$6.7 million related to work at Cabretero and LLA-34.

Non-cash Impairment Charges

(\$000s)	For the three months ended December 31,		For the year ended December 31,	
	2019	2018	2019	2018
Impairment of E&E assets	\$ 17,223	\$ 15,172	\$ 22,767	\$ 15,172
Total non-cash impairment charges before deferred income tax recoveries	\$ 17,223	\$ 15,172	\$ 22,767	\$ 15,172

An impairment of E&E assets of \$17.2 million and \$22.8 million was recorded in the consolidated statement of comprehensive income for the three months and year ended December 31, 2019. The impairment in the fourth quarter of 2019 is primarily associated with the LLA-10 block exploration costs that are won't be recovered as the Company plans to relinquish the block in 2020, post drilling of the Tautaco dry hole. Year to date impairment includes Morpho block costs that won't be recovered as the Company has relinquished the block. The net book value of costs on this block has been impaired to \$nil.

At December 31, 2019 Parex tested its CGU's for PP&E impairment where it was determined that the recoverable amount of the CGU's exceeded their carrying amounts, and therefore the Company's CGU's were not impaired. The recoverable amount was determined using estimated fair value less costs of disposal. Future cash flows were discounted using an after tax rate of 11% with the following prices being used by Parex' independent reserve evaluator at December 31, 2019:

	2020	2021	2022	2023	2024	Thereafter
Brent (\$US/bbl)	67.00	68.00	71.00	73.00	75.00	2% increase per year

The impairment of E&E assets during the three months and year ended December 31, 2018 of \$15.2 million is primarily associated with VMM-9 costs in the Middle Magdalena basin that were unlikely to be recovered by successful development or sale as the block is currently in force majeure for the foreseeable future. The net book value of costs on this block has been impaired to \$nil.

At December 31, 2018 Parex tested its CGU's for PP&E impairment where it was determined that the recoverable amount of the CGU's exceeded their carrying amounts, and therefore the Company's CGU's were not impaired. The recoverable amount was determined using estimated fair value less costs of disposal. Future cash flows were discounted using an after tax rate of 11% with the following prices being used by Parex' independent reserve evaluator at December 31, 2018:

	2019	2020	2021	2022	2023	Thereafter
Brent (\$US/bbl)	63.25	68.50	71.25	73.00	75.50	2% increase per year

For further information regarding the impairment charges for the years ended December 31, 2019 and 2018, 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 - Summary of Significant Accounting Policies of the audited consolidated financial statements for the years ended December 31, 2019 and 2018. 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) (except per share amounts)	Dec. 31, 2019	Sep. 30, 2019	June 30, 2019	March 31, 2019
Average daily oil and natural gas production (boe/d)	54,221	53,045	52,252	51,208
Realized sales price (\$/boe)	53.00	53.59	59.92	52.33
Financial				
Oil and natural gas sales	\$ 289,585	\$ 275,693	\$ 301,750	\$ 246,594
Funds flow provided by operations ⁽¹⁾	\$ 143,269	\$ 142,733	\$ 150,973	\$ 133,505
Per share – basic	1.00	0.99	1.03	0.88
Per share – diluted ⁽¹⁾	0.98	0.97	1.00	0.86
Net income	\$ 87,218	\$ 57,257	\$ 101,505	\$ 82,014
Per share – basic	0.61	0.40	0.69	0.54
Per share – diluted	0.60	0.39	0.67	0.53
Capital Expenditures, excluding corporate acquisitions	\$ 58,321	\$ 48,600	\$ 48,742	\$ 52,533
Total assets (end of period)	\$ 1,684,581	\$ 1,593,802	\$ 1,574,528	\$ 1,657,956
Working capital surplus (end of period) ⁽²⁾	\$ 344,031	\$ 279,949	\$ 240,087	\$ 207,414

(1) Non-GAAP term. See "Non-GAAP Terms" below. In the second quarter of 2019, Parex changed the way it calculates and presents funds flow from operations. Comparative periods have also been adjusted for this change.

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

Three months ended (\$000s) (except per share amounts)	Dec. 31, 2018	Sep. 30, 2018	June 30, 2018	March 31, 2018
Average daily oil and natural gas production (boe/d)	49,300	45,020	42,625	40,586
Realized sales price (\$/boe)	55.42	61.69	61.96	55.98
Financial				
Oil and natural gas sales	\$ 270,599	\$ 250,909	\$ 241,765	\$ 202,450
Funds flow provided by (used in) operations ⁽¹⁾	\$ 154,211	\$ 150,616	\$ (7,937)	\$ 103,737
Per share – basic	0.99	0.97	(0.05)	0.67
Per share – diluted ⁽¹⁾	0.97	0.94	(0.05)	0.66
Net income	\$ 54,060	\$ 88,731	\$ 188,601	\$ 71,512
Per share – basic	0.35	0.57	1.21	0.46
Per share – diluted	0.34	0.55	1.18	0.45
Capital Expenditures, excluding corporate acquisitions	\$ 76,758	\$ 66,808	\$ 100,567	\$ 58,210
Total assets (end of period)	\$ 1,642,120	\$ 1,613,547	\$ 1,529,692	\$ 1,182,764
Working capital surplus (end of period) ⁽²⁾	\$ 218,526	\$ 143,243	\$ 66,050	\$ 205,771

(1) Non-GAAP term. See "Non-GAAP Terms" below. In the second quarter of 2019, Parex changed the way it calculates and presents funds flow from operations.

Comparative periods have also been adjusted for this change. For the three months ended June 30, 2018, funds flow provided by operations includes a \$137.5 million (\$0.88 per share basic) charge for a voluntary tax restructuring, refer to the "Income Tax" section

(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 2019, production of 54,221 boe/d was in excess of production compared to the previous quarter ended September 30, 2019. Revenue and funds flow provided by operations were higher than the previous quarter due to an increase in volumes sold, partially offset by a decrease in realized prices. Working capital increased to \$344.0 million from \$279.9 million at September 30, 2019.

During the third quarter of 2019, production of 53,045 boe/d was in excess of production for the previous quarter ended June 30, 2019. Revenue and funds flow provided by operations were lower than the previous quarter due to a decrease in realized prices, partially offset by an increase in volumes sold. Working capital increased to \$279.9 million from \$240.1 million at June 30, 2019.

During the second quarter of 2019, production of 52,252 boe/d was in excess of production for the previous quarter ended March 31, 2019. Revenue and funds flow provided by operations was higher than the previous quarter mainly due to an increase in realized prices and volumes sold. Working capital increased to \$240.1 million from \$207.4 million at March 31, 2019.

During the first quarter of 2019, production of 51,208 boe/d was in excess of oil production for the previous quarter ended December 31, 2018. Revenue and funds flow provided by operations were lower than the previous quarter mainly due to a decrease in realized prices and volumes sold. Working capital increased to \$207.4 million from \$218.5 million at December 31, 2018 primarily due to the share buy-back program which commenced at the end of Q4, 2018.

During the fourth quarter of 2018, production of 49,300 boe/d was in excess of production from the previous quarter ended September 30, 2018. Revenue was higher than the previous quarter due to an increase in sales volumes partially offset by a decrease in world oil prices in the period. Funds flow provided by operations was higher than the previous quarter also due to increased sales volumes partially offset by a decrease in realized sales prices per barrel. Capital expenditures for the fourth quarter of 2018 were \$76.8 million compared to \$66.8 million in the prior quarter mainly related to drilling on Block LLA-34, Cabrestero Block, and Capachos Block.

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

Consolidated Statements of Comprehensive Income for the three months ended December 31, 2019:

(\$000s) For the three month period ended December 31,	2019	2018
Oil and natural gas sales	\$ 289,585	\$ 270,599
Royalties	(36,717)	(38,068)
Revenue	252,868	232,531
Expenses		
Production	29,183	26,966
Transportation	20,462	19,442
Purchased oil	16,154	3,951
General and administrative	10,911	7,951
Equity settled share-based compensation expense	1,785	2,925
Cash settled share-based compensation expense (recovery)	8,202	(6,842)
Depletion, depreciation and amortization	32,636	30,088
Foreign exchange loss (gain)	5,488	(14,245)
Impairment of exploration and evaluation assets	17,223	15,172
	142,044	85,408
Finance (income)	(1,062)	(1,719)
Finance expense	2,760	4,611
Net finance expense	1,698	2,892
Income before income taxes	109,126	144,231
Income tax expense		
Current tax expense	32,763	21,689
Deferred tax (recovery) expense	(10,855)	68,482
	21,908	90,171
Net income and comprehensive income for the period	\$ 87,218	\$ 54,060

Liquidity and Capital Resources

As at December 31, 2019 the Company had a working capital surplus of \$344.0 million, excluding amounts available under the credit facility, as compared to working capital surplus of \$218.5 million at December 31, 2018. Bank debt was \$nil at December 31, 2019 and December 31, 2018. The credit facility has a current borrowing base of \$200.0 million and is subject to a borrowing base redetermination to be completed by the end of May 2020. At December 31, 2019 Parex held \$396.8 million of cash, compared to \$350.2 million at September 30, 2019 and \$462.9 million at December 31, 2018. The Company's cash balances reside primarily in current accounts with chartered financial institutions, the majority of which are held on account in Canada and Barbados in USD. The decrease in the Company's cash position from December 31, 2018 is mainly a result of 2018 tax payments made and share buy back purchases, partially offset by free cash flow earned during the year.

Parex' senior secured credit facility ("credit facility") with a syndicate of banks has a current borrowing base of \$200.0 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, 2019, the Company is in compliance with all covenants. The next annual review is scheduled to occur at the end of May 2020. As the Company currently has \$nil bank debt and no plans in 2020 to utilize the credit facility, the next re-determination is not expected to impact the Company's current or future operations or reduce the 2020 outlook.

On December 18, 2018 the Toronto Stock Exchange ("TSX") approved the Company's NCIB application to purchase up to 15,041,319 of the Company's common shares for cancellation. The NCIB commenced on December 21, 2018 and the maximum number of shares were repurchased by October 11, 2019 at an average price of Cdn\$20.21.

On December 19, 2019 the TSX approved the Company's NCIB application to purchase up to 13,986,994 of the Company's common shares for cancellation. The NCIB commenced on December 23, 2019 and will terminate on December 22, 2020 or such earlier time as the NCIB is completed or terminated by Parex. In December 2019, the Company repurchased 135,000 shares at an average price of Cdn\$23.76. The Company, pursuant to the Company's NCIB, put in place an automatic share purchase plan with a broker in order to facilitate repurchases. Under the Company's automatic share purchase plan, the Company's broker may repurchase shares under the NCIB during the Company's self-imposed blackout periods. The automatic purchase 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 24 - Commitments and Contingencies of the audited financial statements for the year ended December 31, 2019 for a description of the performance guarantee facility with Export Development Canada 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, 2019 the Company had 143,295,054 common shares outstanding compared to 155,013,908 at December 31, 2018, a decrease of 7.6%. At March 10, 2020 the common shares outstanding has been reduced to 141,023,539 due to the NCIB.

The Company has a stock option plan 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. In 2019, Parex created a new cash or share settled RSU and PSU plan. Under this new plan any employee who chooses share settlement will receive common shares of the Company purchased on the open market, hence there will be no new issuance of common shares from treasury under this new plan. Going forward, it is expected that only the grants under the Company's stock option plan and the exercise of previously issued RSUs and PSUs will result in common shares issued from treasury.

As at March 10, 2020 Parex has the following securities outstanding:

	Number	%
Common shares	141,023,539	96%
Stock options	2,542,177	2%
Restricted and performance share units	1,603,799	1%
	145,169,515	99%

As of the date of this MD&A, total stock options, RSUs and PSUs outstanding represent approximately 3 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 which on December 31, 2019 were \$47.9 million (December 31, 2018 - \$111.6 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 has provided performance security guarantees under the Company's \$150.0 million (December 31, 2018 - \$150.0 million) performance guarantee facility to support approximately \$25.4 million (December 31, 2018 - \$79.7 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. At December 31, 2019, there are an additional \$22.5 million (December 31, 2018 - \$31.9 million) letters of credit that are provided by a Latin American bank on an unsecured basis.

The following table summarizes the Company's estimated commitments as at December 31, 2019:

(\$000s)	Total	<1 year	1 – 3 years	3 – 5 years	>5 years
Exploration	\$ 156,615	\$ 15,370	\$ 52,154	\$ 89,091	\$ —
Office and accommodations ⁽¹⁾	9,845	3,208	3,489	3,148	—
Decommissioning and Environmental Obligations	84,822	8,366	—	—	76,456
Total	\$ 251,282	\$ 26,944	\$ 55,643	\$ 92,239	\$ 76,456

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

Decommissioning and Environmental Liabilities

	Decommissioning	Environmental	Total
Balance, December 31, 2017	\$ 36,774	\$ 15,906	\$ 52,680
Additions	7,974	6,146	14,120
Settlements of obligations during the year	(8,060)	(2,352)	(10,412)
Loss on settlement of obligations	5,531	—	5,531
Accretion expense	2,657	2,231	4,888
Change in estimate - inflation and discount rates	(1,703)	(139)	(1,842)
Change in estimate - costs	2,604	(4,252)	(1,648)
Foreign exchange gain	(3,725)	(1,991)	(5,716)
Balance, December 31, 2018	\$ 42,052	\$ 15,549	\$ 57,601
Additions	10,524	1,355	11,879
Settlements of obligations during the year	(10,536)	(1,229)	(11,765)
Loss on settlement of obligations	359	—	359
Accretion expense	3,166	1,426	4,592
Change in estimate - inflation and discount rates	1,455	170	1,625
Change in estimate - costs	(10,253)	(2,532)	(12,785)
Foreign exchange loss (gain)	477	(48)	429
Balance, December 31, 2019	37,244	14,691	51,935
Current obligation	(4,275)	(4,091)	(8,366)
Long-term obligation	\$ 32,969	\$ 10,600	\$ 43,569

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, 2019, 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 \$63.3 million as at December 31, 2019 (December 31, 2018 - \$70.3 million) with the majority of these costs anticipated to occur in 2023 or later. A risk-free discount rate of 6.74

percent and an inflation rate of 3.1 percent were used in the valuation of the liabilities (December 31, 2018 - 7.5 percent risk-free discount rate and a 3.2 percent inflation rate). The risk-free discount rate and the inflation rate used in 2019 are based on forecast Colombia rates.

Included in the decommissioning liability is \$4.3 million (December 31, 2018 - \$6.6 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 \$21.5 million as at December 31, 2019 (December 31, 2018 - \$20.8 million) with the majority of these costs anticipated to occur in 2020 or later in Colombia. A risk-free discount rate of 6.74 percent and an inflation rate of 3.1 percent were used in the valuation of the liabilities (December 31, 2018 - 7.5 percent risk-free discount rate and a 3.2 percent inflation rate). The risk-free discount rate and the inflation rate used in 2019 are based on forecast Colombia rates.

Included in the environmental liability is \$4.1 million (December 31, 2018 - \$2.7 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 and environmental 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 and environmental 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 5, 2020 with an effective date of December 31, 2019, and dated February 7, 2019 with an effective date of December 31, 2018. 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, 2019 reserves presented are based on GLJ's forecast pricing effective January 1, 2020 and all December 31, 2018 reserves presented are based on GLJ's forecast pricing effective January 1, 2019. Additional reserve information for December 31, 2019 as required under NI 51-101 will be included in the Company's Annual Information Form which will be filed on SEDAR on March 10, 2020. Additional information in respect of our December 31, 2018 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 33 million barrels of oil equivalent gross proved plus probable reserve additions (including acquisitions) during the year ended December 31, 2019 divided by current annual production of 52,687 barrels per day and expressed as a percentage. Reserve additions is calculated as the change in proved plus probable reserves from December 31, 2018 (184.674 million barrels of oil equivalent (net company working interest)) to December 31, 2019 (198.423 million barrels of oil equivalent (net company working interest)) excluding production of approximately 19.3 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 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;
- the Company's plan to relinquish land in 2020;
- the Company's expectation regarding 2020 Brent oil prices and Brent/Vasconia crude differential;
- the Company's anticipated average production and production growth for 2020;
- the Company's anticipated operating netback per boe for 2020;
- the Company's anticipated funds flow provided by operations, funds flow provided by operations per boe, free funds flow for 2020;
- the Company's expected capital expenditures for 2020, its allocation and the Company's plans to fund its 2020 capital program from funds flow provided by operations;
- the Company's estimated outstanding shares end of period for 2020 and underlying assumptions;
- the Company's estimated effective tax rate for 2020;
- the Company's expectation that it will fund its 2020 share buy-back program with free funds flow;
- future growth opportunities;
- the Company's 2020 guidance impacted by varying crude oil prices;
- expectation regarding NCIB;
- expectation with respect to future donations;
- expected effective tax rate and variations thereof;
- terms of the NCIB
- expectation that crude oil inventory in future periods to be in line with normal historic levels;
- the timing of payment of total decommissioning and environmental liability cost;
- the Company's expectations regarding the per boe and G&A expense 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;
- 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;
- terms of the Company's risk management contracts;
- the expected effect of changes in commodity and foreign exchange forward strip prices on the fair value of financial contracts;
- terms of the Company's credit facility including the timing of the next borrowing base redetermination;
- no plans to utilize the credit facility in 2020;
- expectation of common share issuances from the stock option plan and previously issued RSUs and PSUs;
- the Company's expectation that the next redetermination of its credit facility will not impact its current or future operations or reduce the 2020 outlook; and
- estimated amounts, timing and the anticipated sources of funding for the Company's exploration, office and accommodations, environmental, decommissioning and restoration obligations.
- the statements set forth under "Accounting Policies and Estimates" in this MD&A.

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; risk of failure to achieve perceived benefits from voluntary tax restructuring; failure of counterparties to perform under the terms of their contracts; changes to pipeline capacity; risk that Parex' evaluation of its existing portfolio of development and exploration opportunities is not consistent with its expectations; failure to meet expected production targets; risk that the review of strategic repositioning alternatives will not result in a transaction; the risks discussed under "Risk Factors" in the Company's AIF and under "Decommissioning and Environmental Liabilities" 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; timing and number of dry hole write-offs permitted for Colombian tax purposes; anticipated benefits from voluntary tax restructuring; 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; on-stream timing of production from successful exploration wells; operational performance of non-operated producing fields; pipeline capacity; the benefits of initiating a review of strategic repositioning alternatives; 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 or generate sufficient cash flow 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, funds flow provided by operations, funds flow provided by operations per boe, funds flow netback per boe, free funds flow and diluted funds flow per share 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.

Adoption of IFRS 16 Leases had an immaterial impact on netbacks, funds flow provided by operations and EBITDA non-GAAP measures.

Funds flow provided by operations, is a non-GAAP measure that includes all cash generated from operating activities and is calculated before changes in non-cash working capital. In Q2 2019, the Company changed how it presents funds flow provided by operations to present on a comparable basis to peer presentation. Amounts have been restated for prior periods. A reconciliation from cash provided by operating activities to funds flow provided by operations is as follows:

(\$000s)	For the three months ended December 31,		For the year ended December 31,	
	2019	2018	2019	2018
Cash provided by operating activities	\$ 83,766	\$ 213,643	\$ 365,067	\$ 531,555
Net change in non-cash working capital	59,503	(59,432)	205,413	(130,928)
Funds flow provided by operations	143,269	154,211	570,480	400,627

Funds flow provided by operations per boe or funds flow netback per boe, is a non-GAAP measure that includes all cash generated from operating activities and is calculated before changes in non-cash working capital, divided by produced oil and natural gas sales volumes. The Company considers funds flow netback to be a key measure as it demonstrates Parex' profitability after all cash costs relative to current commodity prices and is calculated as follows:

(\$000s)	For the three months ended December 31,		For the year ended December 31,	
	2019	2018	2019	2018
Funds flow provided by operations	\$ 143,269	\$ 154,211	\$ 570,480	\$ 400,627
Company produced oil and natural gas sales in period	5,136,452	4,798,812	19,265,365	16,250,895
Funds flow provided by operations per boe	27.89	32.14	29.61	24.65

Free funds flow, is a non-GAAP measure that is determined by funds flow provided by operations less capital expenditures. The Company considers free funds flow or free cash flow to be a key measure as it demonstrates Parex' ability to fund return of capital, such as the NCIB, without accessing outside funds and is calculated as follows:

(\$000s)	For the three months ended December 31,		For the year ended December 31,	
	2019	2018	2019	2018
Funds flow provided by operations	\$ 143,269	\$ 154,211	\$ 570,480	\$ 400,627
Capital expenditures, excluding corporate acquisitions	58,321	76,758	208,196	302,343
Free funds flow	\$ 84,948	\$ 77,453	\$ 362,284	\$ 98,284

Diluted funds flow per share is calculated by dividing funds flow provided by operations by the weighted average number of shares outstanding. Parex presents diluted 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,		For the year ended December 31,	
	2019	2018	2019	2018
Funds flow provided by operations	\$ 143,269	\$ 154,211	\$ 570,480	\$ 400,627
Weighted average number of shares for the purposes of basic funds flow	142,967	155,403	146,380	155,417
Dilutive effect of share options on potential common shares	2,598	3,900	2,645	4,145
Weighted average number of shares for the purposes of diluted funds flow	145,565	159,303	149,025	159,562

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 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,		For the year ended December 31,	
	2019	2018	2019	2018
Oil and natural gas revenue excluding risk management contracts	\$ 289,585	\$ 270,599	\$ 1,113,622	\$ 965,723
Oil revenue for purposes of sales price per boe	\$ 289,585	\$ 270,599	\$ 1,113,622	\$ 965,723

Denominator (BOEs)

Company produced oil and natural gas sales in period	5,136,452	4,798,812	19,265,365	16,250,895
Purchased oil volumes sold	327,612	83,668	1,091,580	217,540
Total oil and natural gas sales volumes	5,464,064	4,882,480	20,356,945	16,468,435
Sales price per boe	\$ 53.00	\$ 55.42	\$ 54.70	\$ 58.64

Royalties per boe is determined by dividing royalty expense by the total equivalent sales volume and excludes purchased oil volumes. A reconciliation of royalties per boe is provided below:

(\$000s)	For the three months ended December 31,		For the year ended December 31,	
	2019	2018	2019	2018
Royalty expense	\$ 36,717	\$ 38,068	\$ 136,068	\$ 132,735
Denominator (BOEs)				
Company produced oil and natural gas sales in period	5,136,452	4,798,812	19,265,365	16,250,895
Royalty expense per boe	\$ 7.15	\$ 7.93	\$ 7.06	\$ 8.17

Production expense per boe is determined by dividing production expense by the total equivalent sales volume and excludes purchased oil volumes. A reconciliation of production expense per boe is provided below:

(\$000s)	For the three months ended December 31,		For the year ended December 31,	
	2019	2018	2019	2018
Production Expense	\$ 29,183	\$ 26,966	\$ 111,061	\$ 90,037
Denominator (BOEs)				
Company produced oil and natural gas sales in period	5,136,452	4,798,812	19,265,365	16,250,895
Production expense per boe	\$ 5.68	\$ 5.62	\$ 5.76	\$ 5.54

Transportation expense per boe is determined by dividing the transportation expense by the total equivalent sales volumes including purchased oil volumes. A reconciliation of transportation expense per boe is provided below:

(\$000s)	For the three months ended December 31,		For the year ended December 31,	
	2019	2018	2019	2018
Transportation Expense	\$ 20,462	\$ 19,442	\$ 88,974	\$ 57,496
Denominator (BOEs)				
Company produced oil and natural gas sales in period	5,136,452	4,798,812	19,265,365	16,250,895
Purchased oil volumes sold	327,612	83,668	1,091,580	217,540
Total oil and natural gas sales volumes	5,464,064	4,882,480	20,356,945	16,468,435
Transportation expense per boe	\$ 3.74	\$ 3.98	\$ 4.37	\$ 3.49

Environmental Initiatives Impacting Parex

In Colombia there is currently no specific regulation that obliges companies to specifically monitor and report GHG emissions. However in 2017, the Colombian government submitted a bill which sets guidelines to manage climate change, although very little specifics were provided. Although at the present time there is no specific regulations related to climate change or GHG emissions in Colombia, 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 impact of climate change and environmental laws and regulations on Parex, 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.

Changing Investor Sentiment

A number of factors, including the concerns of the effects of the use of fossil fuels on climate change, the impact of oil and gas operations on the environment, environmental damage relating to spills of petroleum products during transportation and indigenous rights, have affected certain investors' sentiments towards investing in the oil and gas industry. As a result of these concerns, some institutional, retail and public investors have announced that they no longer are willing to fund or invest in oil and gas properties or companies or are reducing the amount thereof over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices. Developing and implementing such policies and practices can involve significant costs and require a significant time commitment from the Board, management and employees of the Company. Failing to implement the policies and practices as requested by institutional investors may result in such investors reducing their investment in the Company or not investing in the Company at all. Any reduction in the investor base interested or willing to invest in the oil and gas industry and more specifically, the Company, may result in limiting the Company's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Common Shares even if the Company's operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause a decrease in the value of the Company's assets which may result in an impairment change.

The Company's workforce may be exposed to widespread pandemic

Parex' operations are located in areas relatively remote from local towns and villages and represent a concentration of personnel working and residing in close proximity to one another. Should an employee or visitor become infected with a serious illness that has the potential to spread rapidly, this could place Parex' workforce at risk. The 2020 outbreak of the novel coronavirus (COVID-19) in China and other countries around the world is one example of such an illness. The Company takes every precaution to strictly follow industrial hygiene and occupational health guidelines. There can be no assurance that this virus or another infectious illness will not impact Parex' personnel and ultimately its operations.

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 potential political risks such as: changes in policies 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.

Venezuela Presidential Crisis

A crisis concerning who is the legitimate President of Venezuela has been underway since January 10th, 2019, when the opposition-majority National Assembly declared that incumbent Nicolás Maduro's 2018 re-election was invalid and the body declared its president, Juan Guaidó, to be acting president of the nation. As of February 2019, Guaidó is recognized as the interim president of Venezuela by more than 50 countries including the United States and most Latin American and European countries. Maduro's government states that the crisis is a "coup d'état led by the United States to topple him and control the country's oil reserves." Guaidó denies the coup allegations, saying peaceful volunteers back his movement.

The crisis has had a profound impact on the people of Venezuela and its neighboring countries including Colombia. At this time, it is unknown what the impact will be on the regions oil markets, and Colombia foreign relations and politics.

The Capachos block, which the Company operates is 75 km from the Venezuelan border to Colombia in the department of Arauca. The Company is monitoring the situation closely but to date has not seen any material impacts of the crises on the operations of the Company however, it cannot be foreseen whether this will change in the future.

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.

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 no 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\$). As at the date of this MD&A, Parex has active foreign exchange hedges in place (see "Risk Management Contracts – Foreign Exchange").

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 \$200.0 million syndicated credit 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. At the date of this MD&A bank debt was \$nil. 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, which at current has available working capital, 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.

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, 2019.

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, 2019, 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, 2019 based on the COSO Framework. Based on this evaluation, the officers concluded that as of December 31, 2019, 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, 2019 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, 2019.

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:

	2019		2018	
Salaries, directors' fees and other benefits	\$	4,241	\$	4,315
Equity settled share-based compensation		3,714		5,199
Cash settled share-based compensation		4,934		860
	\$	12,889	\$	10,374

At December 31, 2019 key management personnel are comprised of the Company's directors and seven executives. As at December 31, 2019, there is a Cdn\$8.9 million commitment relating to change of control or termination of employment of the seven executives (December 31, 2018 - Cdn\$8.9 million for the seven executives).

Other related party transactions

The Company did not have any related party transactions with entities outside the consolidated group for the years ended December 31, 2019 and 2018.

Significant Accounting Policies

Refer to note 3 - Summary of Significant Accounting Policies of the December 31, 2019 consolidated financial statements for a summary of significant accounting policies applied by the Company.

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, 2019 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, 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.

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. 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.

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.

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, 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 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. Management continually monitors known and potential contingent matters and makes appropriate provisions by charges to net income when warranted by circumstances.

DIRECTORS

Wayne Foo
Chairman of the Board

Curtis Bartlett

Lisa Colnett

Robert Engbloom

Bob MacDougall

Glenn McNamara

Ron Miller

Carmen Sylvain

David Taylor

Paul Wright

OFFICERS & SENIOR EXECUTIVES

David Taylor
President and Chief Executive Officer

Eric Furlan
Chief Operating Officer

Kenneth G. Pinsky
Chief Financial Officer & Corporate Secretary

Lee DiStefano
President, Parex Colombia & Country Manager

Ryan Fowler
Sr. Vice President, Exploration & Business Development

Michael Kruchten
Sr. Vice President, Capital Markets & Corporate Planning

Jeff Meunier
Vice President, New Ventures

Joshua Share
Vice President, Corporate Services

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TRANSFER AGENT AND REGISTRAR

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RESERVES EVALUATORS

GLJ Petroleum Consultants Ltd.
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ABBREVIATIONS**Oil and Natural Gas Liquids**

bbl(s)	barrel(s)
mbbls	one thousand barrels
bbl(s)/d	barrels of oil per day
BOE or boe	barrel of oil equivalent, using the conversion factor of 6 Mcf: 1 bbl
boe/d	barrels of oil equivalent per day
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day

Other

WTI	West Texas Intermediate
Brent	Brent Ice
Vasconia	Vasconia Crude
FFO	Funds flow provided by operations

"BOEs" may be misleading, particularly if used in isolation. A BOE conversion ratio of six 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.