FRONTERA ENERGY

MANAGEMENT DISCUSSION & ANALYSIS

March 13, 2019
For the year ended December 31, 2018

*Frontera Energy Corporation ("**Frontera**" or the "**Company**") is an oil and gas company formed and existing under the laws of British Columbia, Canada, that is engaged in the exploration, development, and production of crude oil and natural gas in South America, and is committed to working hand in hand with all its stakeholders to conduct business in a socially and environmentally responsible manner. The Company's Common Shares ("**Common Shares**") are listed and publicly traded on the Toronto Stock Exchange ("**TSX**") under the trading symbol "FEC." The Company's head office is located at 333 Bay Street, Suite 1100, Toronto, Ontario, Canada, M5H 2R2 and its registered office is 1188 West Georgia Street, Suite 650, Vancouver, British Columbia, Canada, V6E 4A2.*

Legal Notice – Forward-Looking Information and Statements

*This MD&A is management's assessment and analysis of the results and financial condition of the Company and should be read in conjunction with the accompanying audited Consolidated Financial Statements and related notes for the year ended December 31, 2018 and 2017 ("**Consolidated Financial Statements**"). The preparation of financial information is reported in United States dollars and is in accordance with International Financial Reporting Standards ("**IFRS**") as issued by the International Accounting Standards Board, unless otherwise noted. This MD&A contains certain financial terms that are not considered in IFRS. These non-IFRS measures do not have any standardized meaning and therefore are unlikely to be comparable to similar measures presented by other companies and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with IFRS. These measures are described in greater detail under the heading "Non-IFRS Measures" on page 17.*

Beginning in the fourth quarter of 2018, the Company changed its methodology of reporting production volumes to a Company working interest before royalties basis, from the previous practice of reporting net production after royalties. Production will now equal the total amount of the Company's working interest production (before royalties) and total volumes produced from service contracts. The Company believes that this change in methodology results in greater comparability amongst its industry peer group in Canada and South America, and is more reflective of the activity and cost drivers from its operations. Refer to the "Further Disclosures" section on page 27, for additional information on the change in reporting production.

*Certain statements in this Management Discussion and Analysis ("**MD&A**") constitute forward-looking statements. Often, but not always, forward-looking statements use words or phrases such as "expects," "does not expect," "is expected," "anticipates," "does not anticipate," "plans," "planned," "estimates," "estimated," "projects," "projected," "forecasts," "forecasted," "believes," "intends," "likely," "possible," "probable," "scheduled," "positioned," "goal" or "objective." In addition, forward-looking statements often state that certain actions, events or results "may," "could," "would," "might" or "will" be taken, may occur or be achieved. Such forward-looking statements, including, but not limited to, statements with respect to anticipated levels of production, estimated costs and timing of Frontera's planned work programs and reserves determination, involve known and unknown risks, uncertainties and other factors that may cause the actual levels of production, costs and results to be materially different from the estimated levels expressed or implied by such forward-looking statements.*

*The Company believes the expectations reflected in these forward-looking statements are reasonable, but the Company cannot assure that such expectations will prove to be correct, and thus, such statements should not be unduly relied upon. Factors that could cause actual results to differ materially from those anticipated in these forward-looking statements are described in the Company's Annual Information Form ("**AIF**") for the year ended December 31, 2018, dated March 13, 2019. Although the Company has attempted to take into account important factors that could cause actual costs or operating results to differ materially, there may be other unforeseen factors that increase costs for the Company, and so results may not be as anticipated, estimated or intended.*

Statements concerning oil and gas reserve estimates may also be deemed to constitute forward-looking statements to the extent that they involve oil and gas that will be encountered only if the property in question is developed. The estimated values disclosed in this MD&A do not represent fair market value. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates for all properties due to the effects of aggregation. Disclosed well test results may be preliminary until analyzed or interpreted and are not necessarily indicative of long-term performance or ultimate recovery.

*Certain information included or incorporated by reference in 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. Management believes that the FOFI has been prepared on a reasonable basis, reflecting best estimates and judgments; however, actual results of the Company's operations and the financial outcome may vary from the amounts set forth herein. Any FOFI speaks only as of the date on which it was made and, except as may be required by applicable securities law, the Company disclaims any intent or obligation to update any FOFI, whether as a result of new information, future events or otherwise.*

Additional information with respect to the Company, including the Company's quarterly and annual financial statements and the AIF, have been filed with Canadian securities regulatory authorities and is available on SEDAR at www.sedar.com and on the Company's website at www.fronteraenergy.ca Information contained in or otherwise accessible through the Company's website does not form a part of this MD&A and is not incorporated by reference into this MD&A.

1. MESSAGE TO THE SHAREHOLDERS

A year ago, when I joined Frontera, I focused the Company's efforts on our operating performance and things in our control, while continuing to advance some of the legacy issues that take longer to resolve. In 2018, Frontera made significant progress in safety and operations, while developing a medium-term plan to return the Company to growth through access to new opportunities. So far we have had a good start to the year in 2019 with strong production performance in Colombia, improved oil price and differentials, and we have begun to enhance our portfolio for growth over the medium and long term.

From a corporate perspective, we have implemented organizational changes that will improve Frontera's organizational efficiency and save on G&A costs. We have also amended our hedging policy and practices to protect the balance sheet and capital program while leaving the benefit from the upside of higher oil prices.

In our upstream business, we now have the detailed understanding of our core assets to be confident in our ability to sustain production between 65,000 boe/d and 70,000 boe/d for the next five years, and replace produced reserves each year, by spending between $250 and $300 million in capital. This level of sustainable production in a Brent oil price environment of $60/bbl or higher generates sufficient cash flow to invest to sustain the base and to invest for growth. We successfully constructed and brought onstream the 400,000 bbl/d increase in water handling capacity at Quifa Block, which has added over 3,000 bbl/d to Frontera. We had near field exploration success on the Guatiquia block with the discovery of the Coralillo field where we were able to demonstrate to the Agencia Nacional de Hidrocarburos that the field extended into available acreage, which we were awarded in December and which will enable the drilling of eight to ten additional development wells in 2019 and beyond. We have executed two farm-in agreements in recent months; with CGX Energy Inc. for two highly prospective exploration blocks offshore Guyana and another with Parex Resources Inc. in the Lower Magdalena Valley of Colombia on Block VIM-1. We have also recently had success with the award of two blocks in the Ecuador Intracampos bid round with our consortium partner GeoPark Limited, subject to government approval. In addition to significantly adding to our exploration portfolio, these transactions highlight how Frontera has become a desirable partner within the industry. We will be continuing to add to our inventory of exploration and development opportunities in 2019 with additional farm-in agreements and participation in the Colombia bid round.

On the cost side, the most significant events during 2018 were the cancellation of the ship-or-pay contracts on the Bicentenario and Caño Limon pipelines and the settlement of an arbitration to reduce our tariffs on the P-135 expansion of the Ocensa pipeline. In 2019 Frontera will be looking for improved costs and efficiency gains in our field operations. We will continue work to further reduce our transportation tariffs in Colombia, while maintaining our efforts to simplify our business and divest our non-core midstream and infrastructure assets.

In 2018 our shareholders witnessed increased liquidity in the equity following a two for one share split, the implementation of a share buyback program for 5% of the outstanding shares of the Company, the implementation of a dividend program and the declaration of the first dividend of C$0.33 per share. None of these initiatives were successful in preventing Frontera's shares from decreasing 32% in 2018, a result which is not acceptable to myself, the executive team or our board of directors. We have confidence in the assets and people at Frontera and over time expect to correct the absolute and relative performance of the Company's equity.

Lastly, I would like to thank the people at Frontera for welcoming me as the Chief Executive Officer and working so hard in a relatively short period of time to implement our new strategy, which will deliver the results investors expect in 2019 and beyond.

Richard Herbert
Chief Executive Officer

2. PERFORMANCE HIGHLIGHTS

Financial and Operating Summary

		Q4 2018	Q3 2018	Q4 2017	Year ended December 31 2018	Year ended December 31 2017
Operational Results						
Oil production	(bbl/d)	68,661	62,271	64,559	66,846	70,264
Natural gas production	(boe/d)	3,263	4,122	5,315	4,186	5,784
Production (1)	(boe/d) (2)	71,924	66,393	69,874	71,032	76,048
Oil and gas sales and other revenue	($/boe)	60.06	68.02	56.19	64.73	49.21
Realized loss on risk management contracts	($/boe)	(5.55)	(10.02)	(2.93)	(9.13)	(0.88)
Royalties	($/boe)	(2.94)	(2.83)	(1.35)	(2.42)	(1.05)
Diluent costs	($/boe)	(2.22)	(1.89)	(1.00)	(1.92)	(1.13)
Net sales realized price (3)	($/boe)	49.35	53.28	50.91	51.26	46.15
Production costs (4)	($/boe)	(12.76)	(13.84)	(11.98)	(12.51)	(9.82)
Transportation costs (5)	($/boe)	(12.89)	(13.77)	(14.28)	(12.77)	(13.54)
Operating netback (6)	($/boe)	23.70	25.67	24.65	25.98	22.79
Financial Results						
Oil and gas sales and other revenue	($M)	277,944	382,189	338,509	1,368,227	1,185,040
Realized loss on risk management contracts	($M)	(25,667)	(56,297)	(17,641)	(192,970)	(21,291)
Royalties	($M)	(13,597)	(15,902)	(8,125)	(51,221)	(25,382)
Diluent costs	($M)	(10,291)	(10,647)	(6,016)	(40,544)	(27,162)
Net sales (6)	($M)	228,389	299,343	306,727	1,083,492	1,111,205
Net (loss) income (7)	($M)	(116,631)	45,105	(32,544)	(259,083)	(216,703)
Per share – basic and diluted (8)	($)	(1.17)	0.45	(0.33)	(2.59)	(2.17)
General and administrative	($M)	21,839	22,962	24,450	93,022	104,823
Operating EBITDA (6)	($M)	118,398	93,455	104,316	422,508	393,858
Cash (used) provided by operating activities (9)	($M)	(3,494)	177,627	115,223	312,003	314,423
Capital expenditures (10)	($M)	156,400	124,029	111,213	446,083	236,401
Cash and cash equivalents – unrestricted	($M)	446,132	586,578	511,685	446,132	511,685
Restricted cash short-and long-term	($M)	142,305	199,906	132,401	142,305	132,401
Total cash	($M)	588,437	786,484	644,086	588,437	644,086
Debt and obligations under finance leases	($M)	354,363	352,330	269,229	354,363	269,229

1. Represents working interest production before royalties and total volumes produced from service contracts. Refer to the “Further Disclosures” section on page 27.
2. boe has been expressed using the 5.7 to 1 Colombian Mcf/bbl conversion standard required by the Colombian Ministry of Mines & Energy.
3. Per boe is calculated using sales volumes of the development and producing (“**D&P**”) assets.
4. Per boe is calculated using production.
5. Per boe is calculated using net production after royalties.
6. Refer to the “Non-IFRS Measures” section on page 17. This section also includes a description and details for all per boe metrics included in operating netback.
7. Net (loss) income attributable to equity holders of the Company.
8. The basic and diluted weighted average number of Common Shares are stated on an adjusted post-split basis.
9. Prior periods amounts have been revised to reflect the reclassification of certain changes in non-cash working capital items. For further information on this reclassification adjustment, refer to Note 2 of the Consolidated Financial Statements.
10. Capital expenditures includes costs, net of sales from Exploration and Evaluation (“E&E”) assets.

Highlights for the Year and Fourth Quarter of 2018

Changes to Production Reporting and Non-IFRS Measures

- Beginning in the fourth quarter of 2018, the Company changed its methodology of reporting production volumes to a Company working interest before royalties basis, from the previous practice of reporting net production volumes after royalties. Production will now equal the total amount of the Company's working interest production (before royalties) and volumes produced from service contracts. The Company believes that reporting production on this new basis will result in greater alignment with its industry peers and will be more reflective of daily production activity and operational cost drivers. Refer also to the "Further Disclosures" section on page 27 for additional information on the change in reporting production.
- The Company also changed the composition and terminology of certain non-IFRS measures and eliminated other metrics that are no longer considered in its assessment of operational and financial performance. These changes resulted from a comprehensive review of key performance disclosures to improve the clarity and comparability of the Company's results amongst its industry peer group in Canada and South America. Refer also to the "Non-IFRS Measures" section on page 17.

Financial and Operational Results

- In 2018, production averaged 71,032 boe/d (63,187 boe/d after royalties), within the revised annual guidance of 70,000 to 72,000 boe/d (63,000 to 65,000 boe/d after royalties). Fourth quarter 2018 production of 71,924 boe/d was 8% higher than the third quarter of 2018, and 3% higher than the same quarter of 2017.
- Oil and gas sales and other revenue of $1.4 billion in 2018 was 15% higher compared to the prior year. Net sales for the year (including the impact of realized losses of $193.0 million on risk management contracts, royalties and diluent costs) decreased by 2% compared to 2017.
- Operating netback for 2018 was $25.98/boe, 14% higher than $22.79/boe in 2017.
- The Company reported a net loss for 2018 of $259.1 million ($2.59/share) compared with a net loss of $216.7 million ($2.17/share) in 2017.
- Operating EBITDA in 2018 increased by $28.7 million, or 7%, to $422.5 million compared to the prior year.
- The Company generated $312.0 million of cash from operating activities in the year compared to $314.4 million in the same prior year period, contributing to a strong balance sheet with a total cash position of $588.4 million as at December 31, 2018 (including restricted cash of $142.3 million).
- Capital expenditures during 2018 were $446.1 million compared to $236.4 million in the prior year.

Reduction in Transportation Commitments

- On July 12, 2018, the Company and Oleoducto Central S.A. ("**Ocensa**") reached a successful settlement agreement in an arbitration relating to transportation contracts on the P-135 Project (the "**P-135 Settlement Agreement**"). The P-135 Settlement Agreement is expected to reduce the Company's future transportation commitments by approximately $178.3 million over the term of the contract until June 2025.
- On July 13, 2018, the Company announced that it had exercised its rights to terminate its existing contracts with Oleoducto Bicentenario de Colombia S.A.S. ("**Bicentenario**") and Cenit Transporte y Logistica de Hidrocarburos S.A.S. ("**CENIT**") to transport oil through the Bicentenario ("**BIC**") and Caño Limón ("**CLC**") pipelines, respectively. As a consequence of these terminations, the Company is no longer contractually committed to payments of ship-or-pay fees between July 12, 2018 and October 2028 through the CLC pipeline, and between July 12, 2018 and June 2024 through the BIC pipeline. At the time of their termination, the contracts represented $1.35 billion in future commitments. On December 3, 2018 and January 28, 2019, respectively, the Company was notified that arbitration proceedings concerning the validity of terminating the transportation agreements with Bicentenario and CENIT had commenced. The Company is unaware of any factual basis to support the position of Bicentenario and CENIT. Therefore, the Company intends to defend itself vigorously and claim recovery of damages. Those damages will include, among others, (i) in respect of the BIC Pipeline, approximately $130.0 million for payment claims for letters of credit improperly drawn, service prepayments and outstanding service credits, and (ii) in respect of the CLC Pipeline, for the release of approximately $31.8 million in restricted cash for tariff overcharges.

Oil & Gas Reserves

- The Company reported proved plus probable reserves of 154.9 MMboe at December 31, 2018, resulting in a replacement ratio of 103% of produced 2P reserves from the prior year. Despite the overall increase in 2P reserves, proved net reserves of 104.8 MMboe now represent only 68% of the total 2P reserves compared with 74% of the total 2P reserves in 2017.

Pacific Midstream Limited (“PML”) Update

- On September 11, 2018, the International Finance Corporation and related funds (the “**IFC**”) provided a form of notice exercising PML’s BIC Put Option, which if validly exercised requires the Company to purchase from PML its interest in the BIC pipeline. If completed, the Company’s aggregate ownership interest in the BIC pipeline would be 43.03% (currently 26.39%) at an expected net cost of approximately $34.0 million after the proceeds of the transaction are distributed by PML to its shareholders (gross purchase price of $84.8 million).
- On October 19, 2018, the proceeds from the sale of Petroelectrica de los Llanos Ltd. (“**PEL**”), which had been escrowed during the agreement with the IFC on the acquisition of their interest in PML, were released to the Company. As a result, $45.0 million became unrestricted cash, with the balance of $5.0 million paid to the IFC as a break fee on the termination of the agreement.

Exploration Developments

- On January 29, 2019, the Company signed a farm-in agreement with Parex Resources Inc. (“**Parex**”), which is subject to regulatory approval, whereby the Company will receive a 50% working interest in the VIM-1 Block in the Lower Magdalena Valley basin in Colombia in exchange for funding 100% of the first $10 million of the drilling, testing and completion costs of an exploration well, after which costs on the block will be split 50% with Parex’s subsidiary, Parex Resources (Colombia) Ltd.
- On January 31, 2019, the Company entered in to a farm-in joint venture agreement with CGX Energy Inc. (“**CGX**”), subject to government approval, relating to two shallow water offshore Petroleum Prospecting Licenses in Guyana, the Corentyne and Demerara Blocks. Upon approval, the Company will acquire a 33.333% working interest in the two blocks in exchange for a $33.3 million transfer bonus.
- On March 12, 2019, the Company and GeoPark Limited (“**GeoPark**”) as part of a consortium (Frontera 50%, GeoPark 50%) were awarded production sharing contracts on two blocks in Ecuador's Intracampos Bid Round. The blocks were acquired under an initial four-year exploration period, with the option to extend the exploration period by an additional two years, for a total estimated investment commitment of $64 million, or $32 million net to the Company. The final award is contingent upon regulatory approvals which are expected in April 2019.

Shareholder Enhancement Initiatives

- During 2018, the Company repurchased 1.6 million shares for $17.8 million pursuant to a normal course issuer bid.
- On January 17, 2019, the Company paid a dividend of C$0.33 per common share to shareholders of record at the close of business on January 3, 2019.
- On March 13, 2019, the Company declared a dividend of C$0.165 per common share which will paid on or about April 16, 2019 to shareholders of record at the close of business on April 2, 2019.

3. GUIDANCE

The Company’s 2018 financial and operational results were largely in line with annual guidance as revised and presented on November 7, 2018. The Company met or exceeded its 2018 guidance targets across all its key metrics.

In 2018, production averaged 71,032 boe/d (at the mid-point of the guidance range of 70,000 to 72,000 boe/d). Annual net production averaged 63,187 boe/d (within guidance range of 63,000 to 65,000 boe/d), guidance metrics were met despite the suspension of production from Block 192 in Peru due to a force majeure event in the fourth quarter, which impacted annual production before royalties by approximately 875 bbl/d before royalties (745 bbl/d after royalties).

As previously announced, the Company reduced its capital expenditure guidance due to a capital spending review, which delayed certain planned projects, and capital cost efficiencies achieved this year. Actual capital expenditures totaled $446.1 million in 2018, at the lower end of the $440.0 to $460.0 million guidance range.

Production costs of $12.51/boe and transportation costs of $12.77/boe were both near the mid-point of the guidance ranges for 2018. Operating EBITDA in 2018 totaled $422.5 million, which was near the midpoint of the guidance range of $400.0 to $450.0 million despite the loss of Block 192 production in December.

General and administrative expenses totaled $93.0 million, compared to guidance of $95.0 to $105.0 million, reflecting higher realized savings from the Company’s cost optimization initiatives throughout the year.

The following table reports the actual results for the year end December 31, 2018 against guidance. In addition, no changes have been made to the Company annual guidance for 2019, as previously announced on December 6, 2018.

		2018		2019
		Actual	Guidance (1),(2)	Guidance
Average annual production	(boe/d)	71,032	70,000 to 72,000	65,000 to 70,000
Average annual net production	(boe/d)	63,187	63,000 to 65,000	60,000 to 65,000
Production costs (3)	($/boe)	12.51	12.00 to 13.00	12.50 to 13.50
Transportation costs (4)	($/boe)	12.77	12.50 to 13.50	12.50 to 13.50
Operating EBITDA	($MM)	423	400 to 450	400 to 450
General and administrative	($MM)	93	95 to 105	—
Capital expenditures	($MM)	446	440 to 460	325 to 375

1. The guidance for operating EBITDA, general and administrative, and capital expenditures are aggregate ranges for the year.
2. Current guidance assumes $73.00/bbl Brent, and realized oil price differential of $5.00/bbl.
3. Guidance for production costs is on a production before royalties basis.
4. Guidance for transportation costs exclude the impact of fees paid on suspended pipeline capacity and is on a net production basis.

4. PROVED AND PROBABLE OIL AND GAS RESERVES

For the year ended December 31, 2018, the Company received independent certified reserves evaluation reports ("**Reserves Reports**") for all of its assets, with total net 2P reserves of 154.9 MMboe compared with 154.3 MMboe certified reserves for the year ended 2017. The year-over-year change was mainly caused by annual production, technical revisions in Quifa SW field and the discovery of Coralillo field. Proved net reserves of 104.8 MMboe now represent 68% of the total 2P reserves compared with 74% of the total 2P reserves in 2017.

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

Concurrently, with the filing of this MD&A, the Company has filed the following: (i) the Statement of Reserves Data and Other Oil and Gas Information on Form 51-101F1, (ii) Report on Reserves Data by Independent Qualified Reserves Evaluator on Form 51-101F2 by DeGolyer and MacNaughton, and (iii) the Report of Management and Directors on Oil and Gas Disclosure on Form 51-101F3. These reports have been filed on SEDAR at www.sedar.com.

Reserves as at December 31, 2018 (MMboe (1))								
Country	Field	Proved (P1)		Probable (P2)		Proved + Probable (2P)		Hydrocarbon Type
		Gross	Net	Gross	Net	Gross	Net	
Colombia	Quifa SW block	45.0	38.6	11.8	9.7	56.8	48.4	Heavy oil
	Other heavy oil blocks (2)	35.8	34.2	15.0	14.2	50.8	48.4	Heavy oil
	Light/medium oil blocks (3)	29.9	27.5	23.1	21.2	52.9	48.7	Light and medium oil, associated natural gas
	Natural gas blocks (4)	1.6	1.6	1.1	1.1	2.7	2.7	Natural gas
	Sub-total	**112.3**	**101.9**	**51.0**	**46.2**	**163.2**	**148.2**	Oil and natural gas
Peru	Light/medium oil and natural gas blocks (5)	3.5	2.9	3.8	3.8	7.3	6.7	Light and medium oil, associated natural gas
	Total as at Dec. 31, 2018	**115.8**	**104.8**	**54.8**	**50.0**	**170.5**	**154.9**	Oil and natural gas
	Total as at Dec. 31, 2017	128.7	114.1	44.0	40.2	172.7	154.3	
	Difference	(12.9)	(9.3)	10.8	9.8	(2.2)	0.6	
	2018 Production	25.8	22.9	**Total reserves incorporated**		23.7	23.6	

1. See "Boe conversion" in the "Further Disclosures" section, page 27.
2. Includes Cajua, Jaspe, Quifa North, Sabanero and CPE-6 Blocks.
3. Includes Cubiro, Cravo Viejo, Canaguaro, Guatiquia, Casimena, Corcel, Neiva, Cachicamo, and other producing blocks.
4. Includes La Creciente and Guaduas Blocks.
5. Includes onshore Block 192 and offshore Block Z1.

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

5. FINANCIAL AND OPERATIONAL RESULTS

Production

The following table summarizes the average daily field production, production before royalties and net production from all of the Company's producing fields in Colombia and Peru.

	Average Production (in boe/d)								
	Total field production			Production (1)			Net production		
Producing fields in Colombia	**Q4 2018**	**Q3 2018**	**Q4 2017**	**Q4 2018**	**Q3 2018**	**Q4 2017**	**Q4 2018**	**Q3 2018**	**Q4 2017**
Light and medium oil	31,321	30,680	34,465	29,843	29,121	32,747	28,022	26,949	30,142
Heavy oil	48,807	47,063	47,798	29,844	28,534	28,972	24,963	23,497	26,451
Natural gas	3,947	4,768	6,074	3,263	4,122	5,315	3,263	4,122	5,314
Total production Colombia	**84,075**	**82,511**	**88,337**	**62,950**	**61,777**	**67,034**	**56,248**	**54,568**	**61,907**
Producing fields in Peru (2)									
Light and medium oil	11,055	6,152	4,175	8,974	4,616	2,840	7,650	3,990	2,538
Total production Peru	**11,055**	**6,152**	**4,175**	**8,974**	**4,616**	**2,840**	**7,650**	**3,990**	**2,538**
Total production	**95,130**	**88,663**	**92,512**	**71,924**	**66,393**	**69,874**	**63,898**	**58,558**	**64,445**

	Average Production (in boe/d)					
	Total field production		Production (1)		Net production	
Producing fields in Colombia	**2018**	**2017**	**2018**	**2017**	**2018**	**2017**
Light and medium oil	31,432	37,454	29,787	35,756	27,668	32,888
Heavy oil	47,538	48,413	28,888	29,386	24,347	26,879
Natural gas	4,853	6,603	4,186	5,784	4,186	5,784
Total production Colombia	**83,823**	**92,470**	**62,861**	**70,926**	**56,201**	**65,551**
Producing fields in Peru (2)						
Light and medium oil	10,213	7,638	8,171	5,122	6,986	4,531
Total production Peru	**10,213**	**7,638**	**8,171**	**5,122**	**6,986**	**4,531**
Total production	**94,036**	**100,108**	**71,032**	**76,048**	**63,187**	**70,082**

1. Represents working interest production before royalties, and total volumes produced from service contracts. Refer to the "Further Disclosures" section on page 27.
2. Beginning in Q4 2018, the Company now includes the volumes produced from the service contract in Block 192 as production before royalties. This change has been applied to all periods presented herein. Refer also to the "Peru Royalties - Block 192 Contract" section on page 7 for additional information.

Production for the fourth quarter of 2018 was 71,924 boe/d, an increase by 5,531 boe/d, or 8%, compared to the third quarter of 2018. This quarter-over quarter increase was primarily due to the restart of operations at Block 192 early in the quarter compared to the significant downtime associated with a force majeure event on the NorPeruano pipeline in the prior quarter. However, production from Block 192 was once again shut-in during December as a result of further damage to the pipeline. Production in Colombia was also higher following the completion of the Quifa SW Block water handling expansion project and additional wells drilled in the quarter.

In comparison to the fourth quarter of 2017, production increased by 2,050 boe/d, or 3%, during the fourth quarter of 2018. The increase was primarily due to higher production from Block 192 in Peru which was operational for a total of 64 days this quarter compared to 17 days in the fourth quarter of 2017. The increased production from Peru was offset by natural declines on some of the Company's mature fields in Colombia.

Production for the year ended December 31, 2018 was 71,032 boe/d, compared to 76,048 boe/d in the prior year. The decrease was primarily driven by lower production in Colombia from natural declines in the Guatiquia and La Creciente blocks, temporary water injection restrictions in the Casimena block and a community blockade during the first quarter of 2018, which shut-in production at the Cubiro block. In Peru, the Company increased production by 3,049 boe/d on a year-over-year basis as Block 192 was operational for more days throughout 2018.

Production reconciled to sales volumes

		Q4 2018	Q3 2018	Q4 2017	Year ended December 31 2018	Year ended December 31 2017
Production	**(boe/d)**	**71,924**	**66,393**	**69,874**	**71,032**	**76,048**
Royalties in-kind Colombia	(boe/d)	(6,702)	(7,208)	(5,127)	(6,660)	(5,374)
Royalties in-kind Peru [(1)]	(boe/d)	(1,324)	(627)	(302)	(1,185)	(592)
Net production	**(boe/d)**	**63,898**	**58,558**	**64,445**	**63,187**	**70,082**
Oil inventory (build) draw	(boe/d)	(5,797)	(805)	349	(3,079)	(1,913)
(Settlement) overlift	(boe/d)	(8,792)	5,383	3,032	(768)	769
E&E assets volumes sold [(2)]	(boe/d)	(911)	(898)	(1,420)	(988)	(1,362)
Other inventory movements [(3)]	(boe/d)	1,900	(1,167)	(925)	(440)	(1,596)
Sales volumes	**(boe/d)**	**50,298**	**61,071**	**65,481**	**57,912**	**65,980**
Oil sales volumes	(boe/d)	47,058	56,972	60,279	53,748	60,384
Natural gas sales volumes	(boe/d)	3,240	4,099	5,202	4,164	5,596
Inventory balance						
Colombia	(bbl)	716,893	65,497	92,518	716,893	92,518
Peru	(bbl)	1,344,626	1,481,916	846,195	1,344,626	846,195
Inventory ending balance	**(bbl)**	**2,061,519**	**1,547,413**	**938,713**	**2,061,519**	**938,713**

1. The Company reports the share of production retained by the government of Peru as royalties paid in-kind. Refer also below to the "Peru Royalties - Block 192 Contract".
2. Volumes from E&E assets are excluded from total sales volumes because E&E assets revenues and costs are capitalized under IFRS.
3. Mainly corresponds to quality volumetric compensation and trading volumes.

Oil and gas sales volumes for the three months and year ended December 31, 2018, were lower than the comparable prior year periods primarily due to lower production in Colombia and higher inventory buildup in Peru. During the fourth quarter of 2018, the Company settled an outstanding overlift liability position of 809 Mbbl. In Peru, the Company continues to experience higher inventory buildup relating to unsold production from Block 192 due to the pipeline force majeure event. In Colombia, inventory increased mainly due to lower volume sold and purchases of natural gasoline towards the end of the year.

Colombia Royalties - PAP

The Company makes high-price clause participation ("**PAP**") payments to Ecopetrol S.A. and the Agencia Nacional de Hidrocarburos ("**ANH**") on production at the Quifa, Cubiro, Corcel, Guatiquia, Cravoviejo and Arrendajo blocks. The PAP payments are paid in cash for all blocks except for those relating to the Quifa block, which are paid using in-kind volumes from production. The PAP is applicable as accumulated production has exceeded 5 MMbbl and escalates as oil prices increase above a minimum baseline WTI price. The increase in benchmark oil prices has triggered higher PAP obligations payable both in-kind (reducing the Company's net production) and in cash (increasing royalties).

The Company paid approximately 4.0% (combined cash and in-kind) of its production in the fourth quarter of 2018 as PAP, which was higher than 2.0% in the same period of 2017 and lower than 5.0% in the previous quarter of 2018. For the year ended December 2018, the Company paid 4.2% from production as compared with 1.4% in the same period of 2017. The Company paid in-kind volumes averaging 2,405 bbl/d and 2,115 bbl/d during the fourth quarter and year ended December 2018, respectively. In the third quarter of 2018, the Company paid 2,628 bbl/d as PAP in-kind volumes.

Peru Royalties - Block 192 Contract

The Company does not hold a license or working interest on Block 192 in Peru, as it operates the block through a service contract. Under this contract, the volumes produced are owned by Perupetro and the Company is entitled to in-kind payments on production, which can range from 49% to 84% of production on the block. This percentage is determined by the "R" Factor, which is related to income and expenses in accordance with the service contract. The Company reports the share of production retained by the government as royalties paid in-kind.

As of December 31, 2018, the Company has received in-kind payments for its services of 84% of the production from the block, except in the month of December when it was reduced to 83% with the balance being retained by Perupetro.

Overlift and Settlement

Overlift, or settlement, corresponds to a short-term imbalance between the Company's production and sales volumes. In these instances, the Company lifts barrels from the pipeline system resulting in more volumes sold than produced, which is considered "overlift". Overlift represents an obligation for the Company to deliver the equivalent future production. Settlement occurs when this production is delivered to settle the overlift liability. During overlift, the Company recognizes the sales and an equivalent cost with no margin impact during the quarter. When the overlift is settled, this expense is reversed to recognize the gross margin earned on the related sale in the period of production. Refer to the "Oil and Gas Operating Costs" section on page 11.

Realized and Reference Prices

					Year ended December 31	
		Q4 2018	**Q3 2018**	**Q4 2017**	**2018**	**2017**
Reference price						
Brent	($/bbl)	68.60	75.84	61.46	71.69	54.74
Average realized prices						
Realized oil price	($/bbl)	62.15	70.87	56.00	67.19	50.82
Realized natural gas price	($/boe)	25.90	24.71	21.55	24.09	21.43
Other revenue (1)	($/boe)	0.24	0.25	1.18	0.64	1.17
Net sales realized price						
Oil and gas sales and other revenue	($/boe)	60.06	68.02	56.19	64.73	49.21
Realized loss on risk management contracts	($/boe)	(5.55)	(10.02)	(2.93)	(9.13)	(0.88)
Royalties	($/boe)	(2.94)	(2.83)	(1.35)	(2.42)	(1.05)
Diluent costs	($/boe)	(2.22)	(1.89)	(1.00)	(1.92)	(1.13)
Net sales realized price	**($/boe)**	**49.35**	**53.28**	**50.91**	**51.26**	**46.15**

1. Includes revenue from infrastructure and other assets (including PEL until its disposal on April 19, 2018).

Crude oil prices fell sharply during the fourth quarter of 2018 reaching their lowest level in more than a year with the Brent benchmark price averaging 10% lower than the third quarter of 2018. The reduction in global crude oil prices was mostly attributable to a weaker global economic outlook, lower manufacturing and industrial output and higher oil supply leading to higher than expected crude oil inventories.

Despite this decline during the fourth quarter, Brent oil prices increased by 31% year-over-year to average $71.69/bbl for 2018. Oil prices have risen as a result of stronger oil demand primarily from Asia, supply disruptions due to Organization of Petroleum Exporting Countries production cuts and continued uncertainty in Venezuela and Iran due to international sanctions. For the year-ended December 31, 2018, the Company's net sales realized price increased by 11% to $51.26/boe compared to the prior year as higher oil prices also resulted in higher realized losses on risk management contracts and royalties.

Operating Netback

The following table provides a summary of the Company's quarterly operating netback:

	Q4 2018		Q3 2018		Q4 2017	
	$M	($/boe)	$M	($/boe)	$M	($/boe)
Net sales realized price [(1)]	228,389	49.35	299,343	53.28	306,727	50.91
Production costs [(2)]	(84,441)	(12.76)	(84,560)	(13.84)	(77,040)	(11.98)
Transportation costs [(3)]	(75,748)	(12.89)	(74,210)	(13.77)	(84,682)	(14.28)
Operating Netback [(4)]	**68,200**	**23.70**	**140,573**	**25.67**	**145,005**	**24.65**
		(boe/d)		**(boe/d)**		**(boe/d)**
Sales volumes (D&P) [(5)]		50,298		61,071		65,481
Production [(6)]		71,924		66,393		69,874
Net production [(6)]		63,898		58,558		64,445

1. Per boe is calculated using sales volumes D&P assets. Refer to the "Realized and Reference Prices" section on page 8.
2. Per boe is calculated using production.
3. Per boe is calculated using net production after royalties.
4. Refer to the "Non-IFRS Measures" section on page 17 for details and a description of the operating netback calculation.
5. Sales volumes D&P assets excludes volumes from E&E assets as the related sales and costs are capitalized under IFRS.
6. Refer to the "Production" section on page 6.

Operating netback for the fourth quarter of 2018 was $23.70/boe compared to $24.65/boe in the same quarter of 2017. The decrease was primarily due to the lower net sales realized price, which resulted from higher royalties from the increase in international oil prices and diluent costs due to a change in a diluent pool available in 2018, after the Bicentenario contract termination. The increase in production costs was driven by higher production, workover and maintenance activities on Block 192 in Peru. These factors were partially offset by lower transportation costs due to the increased use of the Ocensa pipeline during this quarter, compared to higher cost transportation alternatives used in the fourth quarter of 2017.

In comparison to the third quarter of 2018, operating netback was 8% lower due to a lower net sales realized price from the decline in the Brent oil price benchmark late in the fourth quarter. On a per boe basis, production and transportation costs both decreased as a result of higher production quarter-over-quarter.

The following table provides a summary of the Company's year-to-date operating netback:

	Year ended December 31			
	2018		2017	
	$M	($/boe)	$M	($/boe)
Net sales realized price [(1)]	1,083,492	51.26	1,111,205	46.15
Production costs [(2)]	(324,400)	(12.51)	(272,482)	(9.82)
Transportation costs [(3)]	(294,471)	(12.77)	(346,300)	(13.54)
Operating Netback [(4)]	**464,621**	**25.98**	**492,423**	**22.79**
		(boe/d)		**(boe/d)**
Sales volumes (D&P) [(5)]		57,912		65,980
Production [(6)]		71,032		76,048
Net production [(6)]		63,187		70,082

References 1 through 6 are consistent with those included in the quarterly Operating Netback table above.

For the year ended December, 31, 2018, operating netback was $25.98/boe and 14% higher than 2017 primarily due to the increase in net sales realized price from the improvement in Brent oil benchmarks and lower transportation costs due to the increased use of the OCENSA pipeline during 2018 compared to higher cost transportation alternatives used in 2017. These factors were partially offset by higher production costs, primarily in Peru, due to the fluctuating operating rates at Block 192 during various unplanned periods of suspension throughout the year. This has led to an increase in workover and maintenance activities during periods when production was shut-in.

Sales

	Three months ended December 31		Year ended December 31	
($M)	**2018**	**2017**	**2018**	**2017**
Oil and gas sales and other revenue [1]	277,944	338,509	1,368,227	1,185,040
Realized loss on risk management contracts	(25,667)	(17,641)	(192,970)	(21,291)
Royalties	(13,597)	(8,125)	(51,221)	(25,382)
Diluent costs	(10,291)	(6,016)	(40,544)	(27,162)
Net sales [2]	**228,389**	**306,727**	**1,083,492**	**1,111,205**
$/boe using (D&P) assets sales volumes	49.35	50.91	51.26	46.15

1. “Oil and gas sales and other revenue” for periods prior to 2018 included in this MD&A are different from those previously reported as a result of the adoption of IFRS 15, effective January 1, 2018. On adoption of the new standard, realized gains and losses on risk management contracts are no longer included in revenue. For further information on this change in presentation, refer to Note 3 of the Consolidated Financial Statements.
2. Beginning in the third quarter of 2018, the Company changed the composition of “Net sales” which had previously been referred to as “Total sales after realized (loss) gain on risk management contracts”. Refer to the “Non-IFRS Measures” section on page 17 for more details.

Net sales for the three months and year ended December 31, 2018, decreased by $78.3 million and $27.7 million, respectively, compared to the same periods in 2017. The following table describes the various factors that had an impact on the decrease in net sales for both periods:

	Three months ended December 31	Year ended December 31
($M; FY analysis in parenthesis)	**2018 - 2017**	**2018 - 2017**
Net sales for the period ended December 31, 2017	306,727	1,111,205
Increase due to 7% higher oil and gas price (FY - 32% higher)	17,921	328,102
Higher realized loss on risk management contracts	(8,026)	(171,679)
Increase in royalties	(5,472)	(25,839)
Decrease due to lower volumes sold of 15,183 boe/d or 23% (FY - lower 8,068 boe/d or 12%)	(78,486)	(144,915)
Increase in diluent costs	(4,275)	(13,382)
Net sales for the period ended December 31, 2018	**228,389**	**1,083,492**

Royalties

	Three months ended December 31		Year ended December 31	
($M)	**2018**	**2017**	**2018**	**2017**
Cash royalties Colombia	13,327	7,871	50,253	22,978
Cash royalties Peru	270	254	968	2,404
Royalties [1]	**13,597**	**8,125**	**51,221**	**25,382**
$/boe using (D&P) assets sales volumes	2.94	1.35	2.42	1.05

1. Previously referred to as “High-price participation payments and cash royalties”.

Royalties represents high-price participation payments, cash royalties and royalties amounts paid to previous owners of certain blocks in Colombia. For the three months and year ended December 31, 2018, increased by $5.5 million and $25.8 million, respectively, compared to the same periods in 2017. The Company’s royalty burden is directly correlated with the increase in benchmark oil prices due to the price sensitivity of PAP in Colombia. Refer to the “Production” section on page 6 for further details of royalties paid in-cash and in-kind.

Oil and gas operating costs

	Three months ended December 31		Year ended December 31	
($M)	**2018**	**2017**	**2018**	**2017**
Production costs	84,441	77,040	324,400	272,482
Transportation costs	75,748	84,682	294,471	346,300
Diluent costs	10,291	6,016	40,544	27,162
Inventory valuation	(12,266)	(613)	(33,265)	(22,076)
(Settlement) overlift	(59,693)	16,927	(16,961)	17,008
Total oil and gas operating costs	**98,521**	**184,052**	**609,189**	**640,876**

Total oil and gas operating costs for the three months and year ended December 31, 2018, decreased by 46% and 5% to $98.5 million and $609.2 million, respectively, from the comparable periods in 2017. Total oil and gas operating costs changed mainly due to the following:

- Production costs were 10% and 19% higher in the three months and year ended December 31, 2018, respectively, compared to the same periods of 2017, mainly as a result of higher production costs from well services in Colombia, and increased workovers and maintenance activities in Peru during periods of force majeure events where production was shut-in at Block 192.

- Transportation costs decreased by 11% and 15% in the three months and year ended December 31, 2018, respectively, compared with the same periods of 2017, due to the lower Ocensa tariff from the P-135 Settlement Agreement and less expensive transportation alternatives used in 2018, following termination of the transportation contracts with Bicentenario and CENIT.

- Diluent costs increased by 71% and 49% in the three months and year ended December 31, 2018, respectively, compared with the same periods of 2017, mainly due to a change in the diluent pool available in 2018, after the Bicentenario contract termination.

- Inventory valuation increased by $11.7 million and $11.2 million in the three months and year ended December 31, 2018, respectively, compared with the same periods of 2017, due to the higher inventory build at year end.

- Settlement of an overlift balance was recognized for the three months and year ended December 31, 2018, as production was delivered in the periods to settle the overlift liability.

Other selected operating costs

	Three months ended December 31		Year ended December 31	
($M)	**2018**	**2017**	**2018**	**2017**
Fees paid on suspended pipeline capacity	—	24,656	82,372	108,831
Payments under terminated pipeline contracts	59,040	—	74,618	—
Reversal of provision related to PAP	(41,079)	(99,622)	(62,911)	(99,622)

Fees paid on suspended pipeline capacity decreased due to the termination of the transportation contracts with Bicentenario and CENIT on July 13, 2018. Payments under terminated pipeline contracts represent the net amounts paid to Bicentenario post-termination of the pipeline contracts. The Company had previously issued $64.4 million of irrevocable standby letters of credit ("**SBLCs**") as a guarantee relating to the transportation contract with Bicentenario. Subsequent to the termination of those contracts, Bicentenario drew the full balance issued under the SBLCs.

During 2018, the Company also recognized the reversal of provisions related to the PAP on certain blocks. The provisions were reversed as external legal and technical opinions supported the Company's interpretation of the relevant contracts. In 2017, the Company also reversed a PAP provision relating to the Corcel Block as an arbitration panel delivered a ruling in favour of the Company.

For further information of other selected operating costs, refer to the "Commitments and Contingencies" section on page 21.

General and Administrative

	Three months ended December 31		Year ended December 31	
($M)	2018	2017	2018	2017
General and administrative	21,839	24,450	93,022	104,823

General and administrative expenses ("**G&A**") for the three months and year ended December 31, 2018, both decreased by 11%, compared to the same periods in 2017. Lower G&A in both periods primarily reflects a reduction in employee-related expenses and the Company's continued efforts to reduce overhead costs.

Depletion, Depreciation and Amortization

	Three months ended December 31		Year ended December 31	
($M)	2018	2017	2018	2017
Depletion, depreciation and amortization	80,461	95,526	316,751	382,246

Depletion, depreciation and amortization expense ("**DD&A**") decreased by 16% and 17% for the three months and year ended December 31, 2018, respectively, compared to periods in 2017. The decrease for both periods was primarily due to lower production volumes and higher reserves from D&P assets that result in a lower DD&A rate.

Impairment, Exploration Expenses and Other

	Three months ended December 31		Year ended December 31	
($M)	2018	2017	2018	2017
Impairment of investment in associates	47,816	—	189,988	—
Impairment of exploration and evaluation assets	67,132	11,953	93,874	1,591
Impairment of properties, plant and equipment	13,899	17,103	18,685	71,840
Impairment of VAT receivable and other assets	4,064	6,377	9,808	7,555
Impairment of PEL power transmission line assets	—	1,035	9,125	42,194
Total impairment	**132,911**	**36,468**	**321,480**	**123,180**
Exploration - pre-licence costs (1) and minimum commitment payments(2)	8,927	—	9,706	—
Rubiales-Piriri contracts - post-termination obligation (3)	—	(694)	—	3,664
Recovery of asset retirement obligations	(15,894)	—	(15,894)	—
Total impairment, exploration expenses and other	**125,944**	**35,774**	**315,292**	**126,844**

1. Costs incurred prior to having obtained the legal rights to explore, and thus were expensed.
2. Payments made to fulfill remaining balance of minimum exploration work commitment for certain blocks in Colombia.
3. Related to the Rubiales-Piriri contracts, which expired on June 30, 2016. Refer to Note 3 of the Consolidated Financial Statements.

In 2018, the Company recognized total impairment and exploration expenses of $315.3 million primarily relating to the following charges:

- $131.0 million on the investment in Bicentenario arising from the termination of its transportation contract and the exercise of the PML Bicentenario Put Option. The impairment was primarily driven by reduced volumes, revenues and changes to the timing and risk of future cash flows and dividends resulting from the terminated ship-or-pay commitments on the BIC pipeline.
- $78.5 million of costs relating to E&E and other oil properties in the Colombia South cash-generating unit ("**CGU**"). The Company concluded that impairment indicators existed on the Llanos-25 block and other Colombia South CGU properties due to a change in development plans arising from exploratory testing results and technical revisions in reserves.
- $47.8 million on the investment in Pacific Infrastructure Ventures Inc. ("**PIV**") as a result of higher risk assessment lowering the expected recoverable amount on future discounted cash flows from the operations of Sociedad Portuaria Puerto Bahía S.A. ("**Puerto Bahia**", a subsidiary of PIV).

- $26.6 million in Peru as a result of exploratory drilling work on the Delfin-Sur 1 well, which did not justify further evaluation. As a result, the well was abandoned and the impairment charge was calculated based on the recoverable amount of the related Peru off-shore CGU.
- $20.3 million with respect to its investment in Interamerican Energy Corp. ("**Interamerican**") and PEL as a result of the final sales process and divestment of those assets during the year.

In 2017, the Company recognized total impairment and exploration expenses of $126.8 million, of which $73.4 million was related to certain oil and gas properties, E&E assets from the Colombia and Peru CGUs. In addition, the Company recognized a charge of $42.2 million with respect to the divestment of its transmission line assets in PEL as the carrying value of the assets was written down to a recoverable amount consistent with a purchase offer.

For further details of all impairment charges, refer to Note 7 of the Consolidated Financial Statements.

Restructuring, Severance and Other Costs

	Three months ended December 31		Year ended December 31	
($M)	**2018**	**2017**	**2018**	**2017**
Restructuring	2,177	—	4,495	—
Severance and other costs	5,915	2,436	10,097	12,617
Total restructuring, severance and other costs	**8,092**	**2,436**	**14,592**	**12,617**

Restructuring, severance and other costs for the three months and year ended December 31, 2018, were $8.1 million and $14.6 million, an increase of $5.7 million and $2.0 million from the comparable periods in 2017, respectively. During 2018, the Company incurred costs with respect to transformation activities to deliver process improvements and operational efficiencies. Severance costs related to personnel reductions as a result of the transformation activities and the implementation of an organizational restructuring plan were recognized in the fourth quarter of 2018. During 2017, the Company incurred costs related to corporate reorganization activities undertaken in the prior year and additional restructuring and severance costs resulting from the Company's 2016 restructuring transaction completed on November 2, 2016.

Non-Operating Costs

	Three months ended December 31		Year ended December 31	
($M)	**2018**	**2017**	**2018**	**2017**
Finance income	7,581	4,620	25,832	17,646
Finance expense	(14,668)	(10,098)	(52,724)	(41,814)
Share of income from associates	8,952	14,809	83,601	76,186
Foreign exchange (loss) gain	(13,087)	(3,472)	(3,375)	1,876

Finance Income and Expenses

Net finance income and expense includes interest on the Company's long-term debt, finance leases and fees on letters of credit, net of interest income received. In 2018, net finance income and expense increased to $26.9 million from $24.2 million in the prior year primarily due to higher interest charges from the increase in long-term debt and other fees associated with the Company's refinancing. Refer to the "Liquidity and Capital Resources" section on page 20.

Share of Income from Associates

The Company holds investments in associates that are accounted for using the equity method of accounting, which requires that the Company increase or decrease the carrying value of its investment by its proportionate share of the net earnings or loss of the underlying investee.

The share of income from associates for the three months ended December 31, 2018, decreased to $9.0 million from $14.8 million in the same period of 2017, mainly due to the Colombian peso ("**COP**") functional currency of certain associates, which depreciated 9% relative to the U.S. dollar ("**USD**") in the quarter. As a result, certain associates recognized a higher unrealized loss on the revaluation of USD denominated debt compared to the prior period. For the year ended December 31, 2018, the share of income from associates increased to $83.6 million mainly due to higher income recognized on the Company's investment in Oleoducto de los Llanos Orientales S.A.

Foreign Exchange (Loss) Gain

Foreign exchange gains or losses primarily result from the movement of the COP against the USD. A significant portion of the Company's working capital and expenditures are denominated in COP. During 2018, the COP depreciated against the USD by 9% (foreign exchange close rate COP/USD was COP$3,249.75 for 2018, and COP$2,984.00 for 2017). The foreign exchange loss in 2018 was $3.4 million compared to a gain of $1.9 million in 2017, primarily due to the impact of the COP's depreciation on the translation of the Company's net working capital balances.

Gain (Loss) on Risk Management Contracts

	Three months ended December 31		Year ended December 31	
($M)	**2018**	**2017**	**2018**	**2017**
Realized loss on risk management contracts	(25,667)	(17,641)	(192,970)	(21,291)
Unrealized gain (loss) on risk management contracts	31,392	(80,774)	107,337	(71,762)
Total gain (loss) on risk management contracts	**5,725**	**(98,415)**	**(85,633)**	**(93,053)**

Risk Management Contracts - Brent Crude Oil

As part of its risk management strategy, the Company uses derivative commodity instruments to manage exposure to price volatility by hedging a portion of its oil production. As at December 31, 2018, the Company had hedges in place for 2.2 MMbbl using put options with a strike price of $55/bbl Brent expiring between January 2019 and September 2019. Consistent with the Company's risk management goals and priorities, the put option strategy helps protect the Company's capital program, debt service requirements, and potential future dividends without limiting the upside benefits of higher oil prices. However, this is constantly re-evaluated in the context of current prices, market expectations and changes in the production forecast.

				Strike Prices	Carrying Amount ($M)	
Type of Instrument	**Term**	**Benchmark**	**Notional Amount / Volume (bbl/d)**	**Put / Call; Call Spreads $**	**Assets**	**Liabilities**
Put options	January 2019 to September 2019	Brent	2,220,000	55.00	9,380	—
December 31, 2018					**9,380**	**—**
Zero-cost collars	January 2018 to October 2018	Brent	12,000,000	49.11 / 61.63	—	(102,104)
Call spreads	October 2018	Brent	600,000	59.00 / 63.88	—	(1,643)
December 31, 2017					**—**	**(103,747)**

Risk Management Contracts - Foreign Exchange

The Company is exposed to foreign currency fluctuations COP. Such exposure arises primarily from expenditures that are incurred in COP and its fluctuation against the USD. The Company monitors its exposure to such foreign currency risks. As at December 31, 2018, the Company has entered into foreign currency derivatives contracts from January to June 2019, for $195 million (Forwards and Zero Cost Collars) to reduce its foreign currency exposure associated with operating expenses incurred in COP.

					Carrying Amount ($M)	
Type of Instrument	**Term**	**Benchmark**	**Notional Amount / Volume USD**	**Put / Call; Par forward COP**	**Assets**	**Liabilities**
Zero-cost collars	January to June 2019	COP / USD	$ 172,500	3,032 / 3,273	—	$ (3,299)
Forwards	January to March 2019	COP / USD	$ 22,500	3,109	—	(1,019)
As at December 31, 2018					**—**	**(4,318)**
As at December 31, 2017					**$ —**	**$ —**

	Assets	**Liabilities**
Total risk management contracts as at December 31, 2018	$ 9,380	$ (4,318)
Total risk management contracts as at December 31, 2017	$ —	$ (103,747)

Income Tax Expense

	Three months ended December 31		Year ended December 31	
($M)	**2018**	**2017**	**2018**	**2017**
Current income tax expense	(5,937)	(10,392)	(30,507)	(36,095)
Deferred income tax (expense) recovery	(10,130)	20,830	11,786	20,830
Total income tax (expense) recovery	**(16,067)**	**10,438**	**(18,721)**	**(15,265)**

The current income tax expense for the fourth quarter of 2018 was $5.9 million. The current income tax expense year to date was $30.5 million, which includes minimum income taxes (presumptive tax) of $24.9 million, a tax of $4.4 million coming from the dividends of investments in associates, and current taxes in countries other than Colombia of $1.2 million. In addition, during the year ended December 31, 2018, the Company recognized an income tax expense of $20.8 million related to the utilization of the deferred tax asset, offset by an income tax recovery of $32.6 million related to the recognition of a deferred tax asset. Total income tax recovery for the fourth quarter of 2018 was $16.1 million compared to a total income tax expense of $10.4 million in the same period of 2017, mainly due to the recognition deferred income tax uses in the fourth quarter of 2018.

For more information, refer to Note 10 of the Consolidated Financial Statements.

Net (Loss) Income

	Three months ended December 31		Year ended December 31	
($M)	**2018**	**2017**	**2018**	**2017**
Net loss (1)	(116,631)	(32,544)	(259,083)	(216,703)
Per share – basic and diluted	(1.17)	(0.33)	(2.59)	(2.17)

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

For the year ended December 31, 2018, the Company reported a net loss of $259.1 million compared to $216.7 million in 2017. This was primarily due to higher impairment charges of $188.4 million and payments under terminated pipeline contracts of $74.6 million. These factors were partially offset by higher net sales in excess of operating costs and lower DD&A expense of $65.5 million. The results for 2018 also included a non-cash loss of $48.1 million resulting from currency translation adjustments on the deconsolidation of PEL following its sale and a $25.6 million loss on the extinguishment of debt from the Company's refinancing in the second quarter of 2018.

Capital Expenditures

	Three months ended December 31		Year ended December 31	
($M)	**2018**	**2017**	**2018**	**2017**
Maintenance and development drilling	92,621	69,666	241,498	169,534
Facilities and infrastructure	48,068	20,262	98,108	29,858
Exploration activities (1)	12,286	19,231	96,534	29,019
Administrative assets and other projects	3,425	2,054	9,943	7,990
Total capital expenditures	**156,400**	**111,213**	**446,083**	**236,401**

1. Includes E&E expenditures, net of sales.

Capital expenditures for the three months and year ended December 31, 2018, were $156.4 million and $446.1 million, 41% and 89% higher than the same periods of 2017, respectively. The Company continues to execute on its active exploration and development drilling program with 12 rigs in operation during the first half of 2018 and an average of 11 rigs in operation in the second half of 2018, including six in the Quifa heavy oil district, three in the light oil-focused Guatiquia Block, and one in the Llanos 25 heavy oil Block. A total of 121 development wells were completed during 2018 compared to 103 development wells in 2017, including new horizontal oil wells in Quifa Block.

In addition, the Company has invested in the expansion of production infrastructure at various blocks including the construction of facilities to expand water handling capabilities at the Quifa Block. The Quifa water handling expansion project was completed on time and on budget, with current water disposal volumes of over 350,000 bbl/d resulting in an incremental 3,000 bbl/d from more than 80 reactivated wells. Full water injection capacity to over 400,000 bbl/d is expected in the near-term as the final pump is commissioned.

Selected Quarterly Information

		2018				2017			
Operational and financial results		Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Oil production	(bbl/d)	68,661	62,271	67,522	68,983	64,559	71,984	72,611	71,965
Natural gas production	(boe/d)	3,263	4,122	4,504	4,875	5,315	5,427	5,922	6,489
Production [1]	(boe/d) [2]	71,924	66,393	72,026	73,858	69,874	77,411	78,533	78,454
Oil and gas natural gas sales volumes	($/boe)	50,298	61,071	67,822	52,440	65,481	63,162	64,908	70,452
Brent price	($/bbl)	68.60	75.84	74.97	67.23	61.46	52.17	50.79	54.57
Oil and gas sales and other revenue	($/boe)	60.06	68.02	67.82	61.34	56.19	47.55	45.71	47.34
Realized loss on risk management contracts	($/boe)	(5.55)	(10.02)	(11.12)	(8.98)	(2.93)	0.31	0.57	(1.39)
Royalties	($/boe)	(2.94)	(2.83)	(2.19)	(1.74)	(1.35)	(0.81)	(0.97)	(1.08)
Diluent costs	($/boe)	(2.22)	(1.89)	(1.74)	(1.88)	(1.00)	(1.21)	(1.22)	(1.08)
Net sales realized price	($/boe)	49.35	53.28	52.77	48.74	50.91	45.84	44.09	43.79
Production costs	($/boe)	(12.76)	(13.84)	(12.44)	(11.11)	(11.98)	(9.87)	(9.04)	(8.58)
Transportation costs	($/boe)	(12.89)	(13.77)	(11.81)	(12.68)	(14.28)	(11.77)	(14.19)	(13.98)
Operating netback [3]	($/boe)	23.70	25.67	28.52	24.95	24.65	24.20	20.86	21.23
Revenue [4]	($M)	265,109	366,511	405,198	283,667	344,862	300,574	290,397	318,592
Net (loss) income [5]	($M)	(116,631)	45,105	(184,436)	(3,121)	(32,544)	(141,115)	(51,542)	8,498
Per share – basic and diluted [6]	($)	(1.17)	0.45	(1.84)	(0.03)	(0.33)	(1.41)	(0.52)	0.08
General and administrative	($M)	21,839	22,962	26,168	22,053	24,450	26,569	26,098	27,706
Operating EBITDA [3]	($M)	118,398	93,455	124,667	85,988	104,316	110,243	86,857	92,442
Capital expenditures [7]	($M)	156,400	124,029	86,813	78,841	111,213	48,563	37,826	38,799

1. Represents working interest production before royalties and total volumes produced from service contracts. Refer to the "Further Disclosures" section on page 27.
2. BOE has been expressed using the 5.7 to 1 Colombian Mcf/bbl conversion standard required by the Colombian Ministry of Mines & Energy.
3. Refer to the "Non-IFRS Measures" section on page 17.
4. Revenue for periods prior to 2018 are different from those previously reported as a result of the adoption of IFRS 15, effective January 1, 2018. On adoption of the new standard, realized gains and losses on risk management contracts are no longer included in revenue. For further information on this change in presentation, refer to Note 3 of the Consolidated Financial Statements.
5. Net (loss) income attributable to equity holders of the Company.
6. The basic and diluted weighted average number of Common Shares are stated on an adjusted post split-split basis.
7. Capital expenditures includes costs, net of sales, from E&E assets.

Over the past eight quarters, the Company's sales have fluctuated due to changes in production, movements in the Brent benchmark oil price, fluctuations in oil price differentials and realized gains and losses arising from risk management activities. Trends in the Company's production levels have resulted from natural declines on existing fields and suspension of operations due to unforeseen circumstances, such as community blockades. The Company has had fluctuating production in Peru as operations at Block 192, which had ramped up during the second half of 2017, have since experienced periods of suspension under force majeure due to community and pipeline issues. Trends in the Company's net income and loss are also impacted most significantly by changes in risk management activities that fluctuate with changes in forward market prices, DD&A and net impairment charges of oil, gas and other assets, along with significant reductions from refinancing and lower administrative costs as the Company exited the restructuring process in November 2016.

Please refer to the Company's previously issued annual and interim management discussion and analysis for further information regarding changes in prior quarters.

Selected Annual Information

($M, except as noted)	As at and for the year ended December 31 2018	2017	2016
Revenue [(1)]	1,320,485	1,254,425	1,237,325
Net (loss) income [(2)]	(259,083)	(216,703)	2,448,523
Per share – basic and diluted ($/share) [(3)]	(2.59)	(2.17)	48.97
Cash and cash equivalents unrestricted	446,132	511,685	389,099
Total assets	2,291,278	2,579,651	2,741,719
Total non-current liabilities	578,822	501,902	515,027
Total liabilities	1,184,090	1,183,270	1,140,684

1. Revenue for periods prior to 2018 are different from those previously reported as a result of the adoption of IFRS 15, effective January 1, 2018. On adoption of the new standard, realized gains and losses on risk management contracts are no longer included in revenue. For further information on this change in presentation, refer to Note 3 of the Consolidated Financial Statements.
2. Net (loss) income attributable to equity holders of the Company.
3. The basic and diluted weighted average number of Common Shares are stated on an adjusted post-split basis.

Revenue increased to $1.32 billion in 2018 from $1.25 billion in 2017 and $1.24 billion in 2016 primarily as a result of higher realized prices from the increase in international oil prices. The increase in international oil prices offset lower production and sales volumes in 2016 as a result of the expiration of the Rubiales-Piriri contracts in June 2016. Net loss for 2018 was greater than 2017 as a result of higher impairment charges and one-time charges relating to the deconsolidation of PEL and loss on debt refinancing. In comparison, the Company recognized net income of $2.45 billion in 2016 largely due to non-cash and one-time items, including the recognition of a net gain on its restructuring transaction of $3.62 billion.

Total assets have decreased from 2016 to 2018 as a result of the change in the Company's corporate strategy from developing through acquisitions to developing through optimizing current assets, monetizing non-core assets through divestment, and additional impairment charges on oil and gas properties and other infrastructure assets. Over the past two years, the Company has continued to generate positive cash flows from operations resulting in a total cash and cash equivalents position of $446.1 million.

Non-IFRS Measures

This MD&A contains the following terms that do not have standardized definitions in IFRS: "operating EBITDA", "operating netback" and "net sales". These financial measures, together with measures prepared in accordance with IFRS, provide useful information to investors and shareholders, as management uses them to evaluate the operating performance of the Company. The Company's determination of these non-IFRS measures may differ from other reporting issuers and therefore are unlikely to be comparable to similar measures presented by other companies. Furthermore, these non-IFRS measures should not be considered in isolation or as a substitute for measures of performance or cash flows as prepared in accordance with IFRS.

Changes in Presentation of Non-IFRS Measures

Beginning in the third quarter of 2018, the Company changed the composition and terminology of certain non-IFRS measures and eliminated other metrics that are no longer considered in its assessment of operational and financial performance. These changes resulted from a comprehensive review of key performance disclosures to improve the clarity and comparability of the Company's financial and operational results amongst its industry peer group in Canada and South America. As a result of this review, the following changes have been incorporated in this MD&A:

- Operating netback:
  - Royalties and diluent cost have been reclassified from operating costs to net sales realized price. Royalties (previously referred to as "PAP and cash royalties") was reclassified as the Company now reports revenue net of royalties in the Consolidated Financial Statements. The cost of diluent is recognized within net sales realized price in order to offset the incremental impact on sales as this cost is partially recovered when the blended product is sold.
- Net sales was previously referred to as "total sales after realized (loss) gain on risk management contracts". In addition, the Company changed the calculation of this measure to also deduct royalties and diluent cost for the same reasons described above. For netback purposes, the Company removes all the effects of trading activities from its per barrel metrics.

The following have been eliminated as non-IFRS measures and will no longer be reported by the Company:

- "Adjusted EBITDA" and "adjusted netback" were removed as non-IFRS measures, as the Company no longer incurs fees paid on suspended pipeline capacity, which represented the most significant adjustment from operating EBITDA. As a result, the Company believes that one measure of EBITDA and netback is more useful for management, analysts, investors and other stakeholders to evaluate its operating performance.

- "Adjusted funds flow from operations ("**FFO**")" and "adjusted FFO netback" were removed as non-IFRS measures, as the Company believes that cash provided by operating activities, which is defined in IFRS, represents a more commonly used and better understood measure of the Company's ability to generate cash from its operations.

All non-IFRS measures reported for previous quarters and included in this MD&A have been recalculated and presented using the approach described above.

Operating EBITDA

EBITDA is a commonly used measure that adjusts net income (loss) as reported under IFRS to exclude the effects of income tax expense, net finance costs and DD&A.

Operating EBITDA represents the operating results of the Company's primary business, excluding the items noted above, including fees paid on suspended pipeline capacity, other investments (such as infrastructure assets), certain non-cash items (such as impairments, foreign exchange and unrealized risk management contracts, and share-based compensation) and gains or losses arising from the disposal of capital assets. In addition, other unusual or non-recurring items are excluded from operating EBITDA as they are not indicative of the underlying core operating performance of the Company.

The following table provides a complete reconciliation of net income (loss) to operating EBITDA:

	Three months ended December 31		**Year ended December 31**	
($M)	**2018**	**2017**	**2018**	**2017**
Net loss [1]	(116,631)	(32,544)	(259,083)	(216,703)
Fees paid on suspended pipeline capacity	—	24,656	82,372	108,831
Payments under terminated pipeline contracts	59,040	—	74,618	—
Share-based compensation	166	2,119	4,042	2,605
Depletion, depreciation and amortization	80,461	95,526	316,751	382,246
Impairment and exploration expenses and other	125,944	35,774	315,292	126,844
Reversal of provision related to PAP	(41,079)	(99,622)	(62,911)	(99,622)
Restructuring, severance and other costs	8,092	2,436	14,592	12,617
Share of income from associates	(8,952)	(14,809)	(83,601)	(76,186)
Equity tax	—	—	—	11,694
Foreign exchange loss (gain)	13,087	3,472	3,375	(1,876)
Finance income	(7,581)	(4,620)	(25,832)	(17,646)
Finance expense	14,668	10,098	52,724	41,814
Unrealized (gain) loss on risk management contracts	(31,392)	80,774	(107,337)	71,762
Other income (loss), net	832	4,322	4,741	5,425
Reclassification of currency translation adjustments	(2,753)	—	48,094	—
Loss on extinguishment of debt	—	—	25,628	—
Income tax expense (recovery)	16,067	(10,438)	18,721	15,265
Non-controlling interests	8,429	7,172	322	26,788
Operating EBITDA	**118,398**	**104,316**	**422,508**	**393,858**

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

Net Sales

Net sales is a non-IFRS subtotal that adjusts revenue to include realized gains and losses from risk management contracts while removing the cost of dilution activities. This is a useful indicator for management as the Company hedges a portion of its oil production using derivative instruments to manage exposure to oil price volatility. This metric allows the Company to report its realized net sales after factoring in these risk management activities. The exclusion of diluent cost is helpful to understand the Company's sales performance based on the net realized proceeds from production net of dilution, the cost of which is partially recovered when the blended product is sold. Net sales does not include the sales and purchases of oil and gas for trading as the gross margins from these activities are not considered significant or material to the Company's operations. Refer to the reconciliation in the "Sales" section on page 10.

Operating Netback

Operating netback is used to assess the net margin of the Company's production after subtracting all costs associated with bringing one barrel of oil to the market. It is also commonly used by the oil and gas industry to analyze financial and operating performance expressed as profit per barrel and is an indicator of how efficient the Company is at extracting and selling its product. For netback purposes, the Company removes the effects of trading activities from its per barrel metrics. Refer to the "Operating Netback" section on page 9.

The following is a description of each component of the Company's operating netback and how it is calculated.

Net sales realized price per boe is calculated using net sales (which includes oil and gas sales and other revenue, realized gains and losses from risk management contracts less royalties and diluent cost) divided by the total sales volumes from (D&P) assets. A reconciliation of this calculation is provided below:

	Three months ended December 31		Year ended December 31	
($M)	**2018**	**2017**	**2018**	**2017**
Net sales	228,389	306,727	1,083,492	1,111,205
Denominator (boe)				
Sales volumes (D&P)	4,627,448	6,024,052	21,137,880	24,082,700
$/boe net sales realized price	49.35	50.91	51.26	46.15

Production cost per boe is calculated using production cost divided by production (before royalties). A reconciliation of this calculation is provided below:

	Three months ended December 31		Year ended December 31	
($M)	**2018**	**2017**	**2018**	**2017**
Production costs	(84,441)	(77,040)	(324,400)	(272,482)
Denominator (boe)				
Production	6,617,000	6,428,388	25,926,773	27,757,541
$/boe production costs	(12.76)	(11.98)	(12.51)	(9.82)

Transportation cost per boe is calculated using transportation cost divided by net production after royalties. A reconciliation of this calculation is provided below:

	Three months ended December 31		Year ended December 31	
($M)	**2018**	**2017**	**2018**	**2017**
Transportation costs	(75,748)	(84,682)	(294,471)	(346,300)
Denominator (boe)				
Net production	5,878,650	5,928,939	23,063,114	25,579,898
$/boe transportation costs	(12.89)	(14.28)	(12.77)	(13.54)

6. LIQUIDITY AND CAPITAL RESOURCES

The Company's principal liquidity and capital resource requirements consist of the following:

- Capital expenditures for exploration, production and development, including growth plans;
- Costs and expenses relating to operations, commitments and existing contingencies; and
- Debt service requirements relating to existing and future debt.

The Company expects to fund its anticipated cash requirements and strategic objectives using current cash and working capital balances, cash flows from operations, and available debt and credit facilities. In accordance with the Company's investment policy, available cash balances are held in interest-bearing savings accounts, term deposits and Colombian mutual funds with high credit ratings and liquidity.

As at December 31, 2018, the Company had total cash balances of $588.4 million (including restricted cash of $142 million), a decrease of $55.6 million as compared to December 31, 2017. This decrease was primarily due to net additions to properties, plant and equipment and E&E assets (after non-cash working capital changes) of $409.5 million as the Company continued to expand development and production facilities across its core assets. The Company also advanced $41.3 million to PIV under the terms of its equity contribution agreement. Additionally, the Company paid $25.5 million of dividends to non-controlling interest. These factors were partially offset by $312.0 million generated from operating activities and the receipt of gross cash proceeds from the assets in Papua New Guinea ($57.0 million). The Company also generated cash on the issuance of $350.0 million senior unsecured notes at a coupon rate of 9.7%, maturing in 2023 (the "**Unsecured Notes**"), which resulted in net cash proceeds of $49.6 million after transaction costs and the repurchase of $250.0 million 10% senior secured notes (the "**Secured Notes**").

Total cash balances include short-and long-term restricted cash of $142.3 million, which are amounts that have been set aside and are not available for immediate disbursement. The main components of restricted cash are long-term abandonment funds and cash collateral required in certain legal processes. Abandonment funds are expected to be released in the long-term as assets are required to be abandoned. Cash collateral for legal processes are expected to be released as the processes are closed.

As at December 31, 2018, the Company had a working capital surplus of $215.7 million, a decrease of $94.3 million as compared to December 31, 2017 primarily due to increased level of capital investment at its production and exploration properties. The Company believes that working capital balances in conjunction with future cash flows from operations and available credit facilities are sufficient to support the Company's normal operating requirements, capital expenditures and financial commitments on an ongoing basis.

Unsecured Notes

The Company's long-term borrowing consists of $350.0 million of the Unsecured Notes issued on June 25, 2018. The Unsecured Notes bear interest at a rate of 9.7% per year, payable semi-annually in arrears on June 25 and December 25 of each year. The Unsecured Notes will mature in June 2023, unless earlier redeemed or repurchased. Proceeds of the Unsecured Notes were partially used to repurchase, at a premium and including accrued interest, the total obligation under the Company's previously issued Secured Notes, which were set to mature in 2021. The remaining proceeds were used for general corporate purposes.

Letter of Credit Facility

On May 17, 2018, the Company replaced its amended and restated secured letter of credit facility (the "**Secured LC Facility**") with a $100.0 million unsecured letter of credit facility (the "**Unsecured LC Facility**") with a maturity date of May 17, 2020. In November 2018, the Unsecured LC facility was reduced to $60.0 million. As of December 31, 2018, the outstanding letters of credit issued and maintained under the Unsecured LC Facility for exploration and operational commitments totaled $33.5 million. The lenders receive an amount equal to 3.0% per annum on any undrawn issued and outstanding amounts of the letters of credit, due and payable in arrears on the last business day of each calendar month. If any amounts are drawn under the Unsecured LC Facility, interest accrues at 6% per annum.

Covenants

The Unsecured Notes are senior, unsecured and rank equal in right of payment with all of the existing and future senior unsecured debt and are guaranteed by the Company's principal subsidiaries. Under the terms of both the Unsecured Notes and the Unsecured LC Facility, the Company may, among other things, incur indebtedness provided that the consolidated debt to consolidated adjusted EBITDA ratio(1) is less than or equal to 3.0:1.0 and the consolidated fixed charge ratio(2) is greater than or equal to 2.5:1.0. In the event that the said financial tests are not met, the Company may still incur indebtedness under certain permitted baskets, including an aggregate amount that does not exceed the higher of $100.0 million and 10% of consolidated net tangible assets. The Company is also permitted to make certain restricted payments, including dividends and share buy-back, in an amount up to $100 million per year, subject to certain financial ratio tests and other conditions being met. As at December 31, 2018, the Company is in compliance with such covenants.

1. *Consolidated Debt to Consolidated Adjusted EBITDA Ratio is defined in the indenture governing the Unsecured Notes as the Consolidated Total Indebtedness as of such date divided by Consolidated Adjusted EBITDA for the most recently ended period of four consecutive fiscal quarters. Consolidated Adjusted EBITDA is defined as the Consolidated Net Income (as defined in the Indenture) plus: i) consolidated interest expense; ii) consolidated income tax and equity tax; iii) consolidated depletion and depreciation expense; iv) consolidated amortization expense; and v) consolidated impairment charge, exploration expense and abandonment costs.*
2. *Consolidated Fixed Charge Ratio is the Consolidated Adjusted EBITDA for the most recent ended period of four consecutive fiscal quarters divided by the consolidated interest expense for such period as defined in the Indenture.*

Commitments and Contingencies

The Company's commitments and contractual obligations as at December 31, 2018, undiscounted and by calendar year, are presented below:

As at December 31, 2018	2019	2020	2021	2022	2023	2024 and beyond	Total
Financial Obligations							
Long-term debt, including interest payments	33,950	33,950	33,950	33,950	366,975	—	502,775
Finance leases	10,100	10,119	7,836	3,322	2,485	—	33,862
Transportation Commitments							
Ocensa P-135 ship-or-pay agreement	67,520	67,520	67,520	67,520	67,520	101,469	439,069
Puerto Bahia take-or-pay agreements	39,996	41,653	41,681	—	—	—	123,330
Oleoducto de los Llanos Orientales S.A. ship-or-pay agreement	50,197	30,732	1,144	—	—	—	82,073
Bicentenario take-or-pay storage agreements	7,489	7,489	7,489	7,489	7,489	5,755	43,200
Other transportation agreements	55,982	49,116	49,116	49,041	48,203	138,887	390,345
Exploration Commitments							
Minimum work commitments	25,526	118,093	26,886	—	—	—	170,505
Other Commitments							
Operating purchases and leases	22,528	14,784	13,898	12,566	11,234	11,724	86,734
Community obligations	8,330	310	—	—	—	—	8,640
Total	**$ 321,618**	**$ 373,766**	**$ 249,520**	**$ 173,888**	**$ 503,906**	**$ 257,835**	**$ 1,880,533**

Ocensa P-135 Project Arbitration Settlement

The Company and Ocensa reached a successful settlement agreement in an arbitration on tariffs and monetary conditions relating to transportation contracts entered into with Ocensa concerning the P-135 Project. Under the terms of the P-135 Settlement Agreement, the Company has committed to ship 30,000 barrels of oil per day at $6.3601 per barrel (adjusted at 2.57% inflation per year until 2023 and thereafter, pursuant to applicable regulation), on the Ocensa P-135 Project through June 2025. As a result of the P-135 Settlement Agreement, total commitments for the Ocensa P-135 Project at the time of the settlement were reduced by $178.3 million.

Termination of Transportation Agreements

On July 13, 2018, the Company announced that it had exercised its rights to terminate its contracts with CENIT to transport oil through the CLC pipeline, and with Bicentenario to transport oil through the BIC pipeline. As a consequence of these terminations, the Company is no longer contractually committed to payments of ship-or-pay fees between July 12, 2018 and October 2028 through the CLC pipeline, and between July 12, 2018 and June 2024 through the BIC pipeline. On the date of termination, commitments under contracts totalled $1.35 billion and were excluded from the commitments table above. Prior to the termination of these contracts, there were extended periods of time when the Company was paying for service pursuant to these contracts but not receiving service. As a result, in addition to making payments pursuant to these contracts, the Company had to transport its oil through other pipelines or by other means. Accordingly, termination of these contracts will eliminate duplication and reduce the Company's aggregate transportation costs.

On July 16, 2018 and July 17, 2018, the Company received notices from Bicentenario and CENIT, respectively, disputing the grounds for the termination of the transportation agreements. The Company was notified on January 28, 2019 and December 3, 2018, respectively, that arbitration proceedings concerning the validity of the terminations with Bicentenario and CENIT has commenced before the Center for Arbitration and Conciliation of the Bogota Chamber of Commerce. The Company is unaware of any factual basis to support the position of Bicentenario and CENIT. Therefore, the Company intends to defend itself vigorously and claim recovery of damages. Those damages will include, among others, (i) in respect of the BIC Pipeline, approximately $130.0 million for payment claims for letters of credit improperly drawn, service prepayments and outstanding service credits, and (ii) in respect of the CLC Pipeline, for the release of approximately $31.8 million in restricted cash for tariff overcharges. As at December 31, 2018, a total of $80.2 million in disputed payments were not made since the termination of these contracts.

The Company continues to have existing take-or-pay contracts for storage in Coveñas with Bicentenario for $43.2 million, and offloading facilities in Araguaney and usage of maritime facilities in Coveñas with CENIT for $153.2 million. In addition, the Company also has take-or-pay commitments for the Monterey-Araguaney pipeline with CENIT, which connects the Oleoducto de los Llanos Orientales S.A. ("**ODL**") and Bicentenario pipelines, totalling $111.4 million.

Ocensa Transportation Rights

Pursuant to an assignment agreement with Transporte Incorporado S.A.S ("**Transporte Incorporado**"), an entity owned by the Darby Private Equity Fund, the Company is entitled to Transporte Incorporado's transport capacity rights through the OCENSA pipeline at a set monthly premium through March 31, 2024. Transporte Incorporado also maintains a unilateral right under the assignment agreement, effective April 1, 2019, under which the assignment agreement would be terminated, and the transport capacity rights would be transferred to the Company. On November 28, 2018, Transporte Incorporado S.A.S. informed the Company of its intention to exercise the unilateral right to terminate the assignment agreement, effective April 1, 2019. If exercised, the Company would reacquire the capacity rights for an estimated net payment of $47.0 million.

Puerto Bahia Equity Contribution Agreement

Puerto Bahia operates a multipurpose port facility in the Bay of Cartagena, one of the largest trade hubs in Latin America. The port is adjacent to the Bocachica access channel of the Cartagena Bay, with a depth of approximately 20.5 metres and is strategically located near the Cartagena Refinery and the Panama Canal. Existing facilities offer deep-water capability, which makes the Port Facility the only multi-purpose terminal in Colombia capable of receiving Panamax ships (large cargo vessels) and Suezmax tanks (liquid purpose vessels) simultaneously.

On October 4, 2013, Pacinfra Holding Ltd. ("**Pacinfra**", a subsidiary of the Company), PIV, Puerto Bahia and Wilmington Trust, National Association (as Collateral and Administrative Agent), entered into an equity contribution agreement, pursuant to which Pacinfra and PIV agreed to jointly and severally cause equity or debt contributions to Puerto Bahia up to the aggregate amount of $130.0 million, in various circumstances, including circumstances relating to Puerto Bahia's ability to make payments towards its existing bank debt obligations. During the year ended December 31, 2018, Pacinfra advanced loans to Puerto Bahia as required by the equity contribution agreement totaling $41.3 million bearing interest of 14.0%, and a default interest rate of 16.0% in the event of nonpayment upon maturity in relation to PIV's Puerto Bahia port facility project. As at December 31 2018, the Company has assessed these loans as having full value.

Reversal of Provision Related to High-Price Clause

Upon acquisition of certain exploration and production contracts via business combination transactions in prior years, in accordance with IFRS 3 Business Combinations, a contingent liability provision was recognized with respect to disagreements with the ANH on interpretations of the high-price participation clause for each designated exploitation area within a block under contract.

As at December 31, 2017, the Company reversed $99.6 million in contingent liability provisions related to the Corcel Block upon receipt of a ruling on December 6, 2017, from an arbitration panel in favour of the Company's position. Subsequently, the ANH filed requests for annulment of the arbitration panel's decision with the Consejo de Estado (Colombia's highest administrative court), which were rejected by such court on November 21, 2018 and January 18, 2019. As such, the arbitrators ruling in favour of the Company remains upheld. In 2018, the Company commenced a process to review other contingent liability provisions previously recognized, and reversed a further $62.9 million for two blocks. The reversal was supported by external legal and technical opinions supporting the Company's interpretation of the relevant contracts. The reversals were recognized as a recovery in the Consolidated Statements of Loss for the years ended December 31, 2018 and 2017. The Company and the ANH continue to be in discussions concerning PAP in other contracts.

The Company continues to not disclose the provision amounts recognized, as required by paragraphs 84 and 85 of IAS 37 Provisions, Contingent Liabilities and Contingent Assets, on the grounds that this would be prejudicial to the outcome of potential disputes with the ANH.

Tax Reviews in Colombia and Peru

The Colombian tax authority, the Departamento de Impuesto y Aduanas Nacionales ("**DIAN**"), is reviewing certain income tax deductions with respect to the special tax benefit for qualifying petroleum assets as well as other exploration expenditures. As at December 31, 2018, the DIAN reassessed $111.2 million of tax owing, including estimated interest and penalties, with respect to the denied deductions. The Company believes that disagreements with the DIAN related to the denied income tax deductions will be resolved in favour of the Company. No provision with respect to income tax deductions under dispute has been recognized as at December 31, 2018.

The Peruvian tax authority, the Superintendencia Nacional de Administración Tributaria ("**SUNAT**"), completed a tax audit for the taxation year 2013, which resulted in the denial of certain expenses of approximately $21.5 million, relating to the Company's joint investment in Block Z-1. The Company believes that the disagreements with the SUNAT related to the denial of expenses will be resolved in favour of the Company. No provision with respect to the expenses under dispute has been recognized as at December 31, 2018.

7. OUTSTANDING SHARE DATA

The Company has the following outstanding share data as at March 12, 2019:

	Number
Common shares [(1)]	96,378,276
Deferred share units ("**DSUs**") [(2)]	178,721
Restricted share units ("**RSUs**") [(3)]	1,068,584

1. On June 26, 2018, the Company completed a two-for-one share split with shareholders of record receiving an additional common share for every share held. All related share and per share information has been updated to reflect the post-split share count.
2. DSUs represent a future right to receive Common Shares (or the cash equivalent) at the time of the holder's retirement, death or the holder otherwise ceasing to provide services to the Company. Each DSU awarded by the Company approximates the fair market value of a common share at the time the DSU is awarded. The value of DSUs increases or decreases as the price of the Common Shares increases or decreases, thereby promoting alignment of interests of a DSU holder with shareholders. DSU settlements may be made, in the sole discretion of the Compensation and Human Resources Committee of the Board, in Common Shares, cash or a combination thereof. Only directors are entitled to receive DSUs.
3. RSUs represent a right to receive Common Shares (or the cash equivalent) at a future date as determined by the established vesting conditions. RSUs are granted with vesting conditions that are based on continued service or achievement of personal or corporate objective. The value of RSUs increases or decreases as the price of the Common Shares increases or decreases, thereby promoting alignment of interests of an RSU holder with shareholders. Settlement may be made, in the sole discretion of the Compensation and Human Resources Committee of the Board, in Common Shares, cash or a combination thereof. Vesting of RSUs is determined by the Compensation and Human Resources Committee of the Board in its sole discretion and specified in the Award agreement pursuant to which the RSU is granted.

Share Repurchases

On July 13, 2018, the Company received approval from the TSX to purchase up to 3,543,270 Common Shares over a twelve month period commencing on July 18, 2018, under a normal course issuer bid ("**NCIB**"). The amount eligible for purchase under the NCIB represented approximately 3.5% of the Company's issued and outstanding Common Shares at the time of the NCIB. Effective December 21, 2018, the NCIB was amended to increase the maximum number of shares it is authorized to purchase under the NCIB to 5,000,583 Common Shares (representing approximately 5.0% of its issued and outstanding Common Shares as at July 9, 2018). For the year ended December 31, 2018, the Company has purchased for cancellation 1,590,585 Common Shares at a total cost of $17.8 million.

Dividends

On December 5, 2018, the Company adopted a dividend policy, which includes an initial cash dividend of C$0.33 per Common Share or approximately $25 million (the "**Initial Dividend**") and targeted quarterly cash dividends of approximately $12.5 million during periods in which Brent oil prices sustain an average price of $60/bbl or higher. The payment of any specific quarterly dividend will be subject to approval of the Board in its discretion. The Initial Dividend was paid on January 17, 2019 to shareholders of record at the close of business on January 3, 2019. The Company did not pay a dividend from 2016 through 2018.

In connection with the adoption of the dividend policy, the Company adopted a Dividend Reinvestment Plan ("**DRIP**") to provide shareholders who are resident in Canada with the option to have the cash dividends declared on their common shares reinvested automatically back into additional common shares, without the payment of brokerage commissions or service charges. The DRIP was taken up by 23.8% of shareholders of the Company's outstanding shares as of the record date resulting in the issuance of 625,963 common shares.

On March 13, 2019, the Company declared a dividend of C$0.165 per common share which will paid on or about April 16, 2019 to shareholders of record at the close of business on April 2, 2019.

8. RELATED-PARTY TRANSACTIONS

The following tables provide the transaction amounts, total balances outstanding (before impairment) and commitments with related parties, as at and for the years ended December 31, 2018 and 2017:

($M)		Accounts Receivable	Accounts Payable	Commitments	Cash Advance	Loans / Debentures Receivable (1)	Interests Receivable (1)
ODL (2)	2018	9,116	1,481	82,073	—	—	—
	2017	421	231	130,303	—	—	—
Bicentenario (2)	2018	15,522	1	43,200	87,278	—	—
	2017	13,380	469	902,375	87,278	—	—
PIV	2018	4,624	1,104	123,330	17,741	114,134	37,158
	2017	5,926	1,598	158,179	17,741	76,552	26,331
Interamerican (3)	2018	—	—	—	—	—	—
	2017	145	72	—	—	2,224	362
CGX	2018	—	—	—	—	25,945	2,186
	2017	120	—	—	—	16,122	1,516

		Three months ended December 31			Year ended December 31		
($M)		Sales	Purchases / Services	Interest Income (1)	Sales	Purchases / Services	Interest Income (1)
ODL	2018	—	12,354	—	1,359	46,472	—
	2017	978	12,881	—	3,973	50,135	—
Bicentenario	2018	—	1,306	—	—	59,448	—
	2017	—	30,384	—	—	127,333	—
PIV	2018	20	8,410	3,158	23	29,162	10,828
	2017	—	8,810	2,090	—	35,600	8,234
Interamerican	2018	—	—	(166)	—	—	83
	2017	74	1	84	407	24	338
CGX	2018	1	—	336	459	—	1,026
	2017	526	—	208	526	—	716

1. Amounts presented based on contractual payment obligations, prior to impairments.
2. The Company receives dividends from associate investees, ODL and Bicentenario. Accounts receivable balances for the parties include $22.8 million of dividends receivable (December 31, 2017: $Nil) (Refer to Note 16 of the Consolidated Financial Statements).
3. Interamerican was sold, effective October 2018 (Refer to Note 13 of the Consolidated Financial Statements). and was determined to no longer be a related party as at December 31, 2018.

For further details on the related party transactions, including key management compensation, refer to Note 24 of the Consolidated Financial Statement.

9. RISKS AND UNCERTAINTIES

The Company is exposed to a variety of risks, including but not limited to, operational, financial, competitive, political and environmental risks.

The Company is exposed to operational risks such as unsuccessful exploration and exploitation activities, inability to find new reserves that are commercially and economically feasible, uneconomic transportation methods, premature declines of reservoirs, changes to environmental regulations and other customary operating hazards and risks. The Company attempts to mitigate these risks by employing highly skilled employees and utilizing available technology. Furthermore, the Company maintains insurance coverage that is consistent with industry practices to protect against insurable operating losses.

The Company is also 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.

The Company considers the risks identified above as the most significant risks associated with the disclosure contained in the Consolidated Financial Statements and this MD&A. The list above does not contain all of the risks associated with an investment in the securities of the Company. For a more comprehensive discussion of the risk and uncertainties that could have an effect on the business and operations of the Company, investors are urged to review the Company's AIF and Consolidated Financial Statements for the year ended 2018, copies of which are available on SEDAR at www.sedar.com.

10. ACCOUNTING POLICIES, CRITICAL JUDGMENTS AND ESTIMATES

The Consolidated Financial Statements have been prepared in accordance with IFRS as issued by the International Accounting Standards Board, and with interpretations of the International Financial Reporting Interpretations Committee, which the Canadian Accounting Standards Board has approved for incorporation into Part 1 of the CPA Canada Handbook - Accounting. A summary of significant accounting policies applied is included in Note 2 of the Consolidated Financial Statements. The Company has not early adopted any standard, interpretation or amendment that has been issued but is not yet effective. Recent accounting pronouncements of significance or potential significance are described in Note 2 of the Consolidated Financial Statements, including management's evaluation of impact and implementation progress.

The preparation of the Consolidated Financial Statements in accordance with IFRS requires the Company to make judgments in applying its accounting policies, estimates and assumptions about the future. These judgments, estimates and assumptions affect the reported amounts of assets, liabilities, revenues and other items in net operating earnings or loss and the related disclosure of contingent assets and liabilities included in the Consolidated Financial Statements. The Company evaluates its estimates on an ongoing basis. The estimates are based on historical experience and on various other assumptions that the Company believes are reasonable under the circumstances. These estimates form the basis for making judgments about the carrying value of assets and liabilities and the reported amounts of revenues and other items. Actual results may differ from these estimates under different assumptions or conditions. A summary of the more significant judgments and estimates made by management in the preparation of its financial information is provided in Note 2 of the Consolidated Financial Statements.

11. INTERNAL CONTROL

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

The control framework used to design the Company's ICFR is based on the framework established in Internal Control - Integrated Framework (2013) by the Committee of Sponsoring Organizations of the Treadway Commission.

The Company's ICFR are designed to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company's ICFR may not prevent or detect all misstatements because of inherent limitations.

Management has evaluated the effectiveness of the Company's ICFR as at December 31, 2018. Based on this assessment, the Company's Chief Executive Officer and its Chief Financial Officer concluded that the Company's ICFR were effective as at December 31, 2018.

There have been no changes in the Company's ICFR during the quarter ended December 31, 2018, that have materially affected, or are reasonably likely to materially affect, its ICFR.

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

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

Based on Management's evaluation, which was carried out to assess the effectiveness of the Company's DC&P, the Company's Chief Executive Officer and its Chief Financial Officer, concluded that the Company's DC&P were effective as at December 31, 2018.

12. FURTHER DISCLOSURES

Production Reporting

Beginning in the fourth quarter of 2018, the Company changed its methodology of reporting production volumes to a Company working interest before royalties basis, from the previous practice of reporting net production after royalties. Production will now equal the total amount of the Company's working interest production before royalties, and total volumes produced from service contracts. The latter refers to the total volumes produced under an oil extraction services contract with Perupetro on Block 192 in Peru. Under this contract, the volumes produced are owned by Perupetro and the Company is entitled to in-kind payments on production, which can range from 44% to 84% of production on the Block. This percentage is determined by the "R" Factor which is related to income and expenses in accordance with the service contract. The Company reports the share of production retained by the government under the contract as royalties paid in-kind in this MD&A.

The Company believes that this change in methodology results in greater comparability amongst its industry peer group in Colombia and Latin America, and is more reflective of the activity and cost drivers from its operations.

Refer also to the "Non-IFRS Measures" section on page 17.

Boe Conversion

The term "boe" is used in this MD&A. Boe may be misleading, particularly if used in isolation. A boe conversion ratio of cubic feet to barrels is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In this MD&A, boe has been expressed using the Colombian conversion standard of 5.7 Mcf: 1 bbl required by the Colombian Ministry of Mines and Energy.

Abbreviations

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

bbl	Oil Barrels	**Mcf**	Thousand cubic feet
bbl/d	Barrels of oil per day	**PAP**	High-price clause participation
boe	Barrels of oil equivalent	**P1**	Proved reserves
boe/d	Barrels of oil equivalent per day	**P2**	Probable reserves
D&P	Development and producing	**Q**	Quarter
E&E	Exploration and evaluation	**WTI**	West Texas Intermediate
FY	Full year	**2P**	Proved reserves + Probable reserves
Mbbl	Thousands of oil barrels	**$**	U.S. dollars
MMbbl	Millions of oil barrels	**$M**	Thousand U.S. dollars
MMboe	Millions of oil equivalent barrels	**$MM**	Million U.S. dollars