MANAGEMENT DISCUSSION & ANALYSIS

March 4, 2020
For the year ended December 31,2019

*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 1055 West Georgia Street, 1500 Royal Centre, P.O. Box 11117, Vancouver, British Columbia, Canada V6E 4N7.*

Legal Notice – Forward-Looking Information and Statements

*This Management Discussion and Analysis ("**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, 2019 and 2018 ("**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" section on page 18.*

Certain statements in this 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 estimates and/or assumptions in respect of production levels, operating EBITDA, capital expenditures (including plans and projects related to drilling, exploration activities, and infrastructure), cost savings, and obtaining regulatory approvals, 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. These forward-looking statements are made as of the date of this MD&A and the Company disclaims any intent or obligation to update any forward looking statements, whether as a result of new information, future events or otherwise, unless required pursuant to applicable laws. Risk and assumptions that could cause actual results to differ materially from those anticipated in these forward-looking statements are described under the heading "Forward-Looking Information" in the Company's Annual Information Form ("**AIF**") for the year ended December 31, 2019, dated March 4, 2020. 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 and therefore 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.

*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 reasonable 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 the Company disclaims any intent or obligation to update any FOFI, whether as a result of new information, future events or otherwise, unless required by applicable laws.*

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

During 2019 Frontera demonstrated that our strategy is working. Our goal is to execute our strategy and deliver a long-term track record of sustainability in production and reserves, with a continuous focus on cost reduction and efficiency improvement. In 2019, the execution of our strategy saw the Company deliver favourable operating and financial metrics while maintaining daily production and growing reserves. We also added exciting exploration growth opportunities offshore Guyana, onshore Ecuador and added three new blocks in Colombia as part of two successful Agencia Nacional de Hidrocarburos ("**ANH**") bid rounds. In 2020, we have allocated capital to those projects which may have the potential to be transformational for the Company. Our farm in joint venture, executed in February 2019 with Parex Resources on the VIM-1 block in the Lower Magdalena Valley in Colombia, has already delivered an exciting exploration discovery.

In our upstream business, our core assets had a strong year with Quifa growing production and reserves following the water handling expansion project completed at the end of 2018. At CPE-6, successful development drilling increased daily production by more than three times. CPE-6 also saw exploration success, which expanded the potential of the block to the north and to the south. This is yet another example of how we can have material near-field exploration success in close proximity to our core producing assets. Our light oil business had strong production throughout the year despite very little drilling activity and the deferral of our water flood pressure maintenance project at Cubiro. We are in the process of restarting development drilling on the western flank of the Guatiquia block in the Coralillo field, which we hope will contribute to our goal of maintaining balance between our light and medium and heavy oil production.

Our ongoing focus on taking costs out of the business delivered in 2019 with an 18% reduction in G&A costs, a 4% reduction in operating costs per boe and a 2% reduction in transportation costs per boe. We have implemented an asset team model in our operations group and expect to see continued efficiency improvements and cost savings throughout 2020. On the transportation cost side, we will begin to see some legacy contracts expire in the coming years, which we expect will eventually lead to a $2-3/boe decrease in our transportation costs by 2024. Although we have experienced a challenging start to 2020 due to the economic uncertainty arising from the COVID-19 (Coronavirus) outbreak and the related impacts on global demand and oil prices, we remain focused on protecting the Company's balance sheet and capital programs. For 2020, we have approximately 40% of expected net production hedged, generally at Brent oil prices of $58/bbl and above, which has already helped to protect against lower realized oil prices.

We continue to focus on a number of initiatives relating to our midstream and infrastructure investments, which will make the Company easier to understand and more attractive from an investment perspective.

In 2019, our shareholders continued to witness increased liquidity in equity thanks to the distribution of C$1.645 in dividends since the inception of our dividend policy and the execution of our share buyback program, which saw us buy back over 2.6 million shares. 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 their hard work and dedication to the Company and our strategy.

Richard Herbert
Chief Executive Officer

2. PERFORMANCE HIGHLIGHTS

Financial and Operational Summary

		Q4 2019	Q3 2019	Q4 2018	Year ended December 31 2019	Year ended December 31 2018
Operational Results						
Oil production	(bbl/d)	68,681	67,930	68,661	68,474	66,846
Natural gas production	(boe/d)	2,224	2,283	3,263	2,401	4,186
Production (1)	(boe/d) (2)	70,905	70,213	71,924	70,875	71,032
Oil and gas sales and other revenue	($/boe)	58.95	57.90	60.06	60.13	64.73
Realized loss on risk management contracts	($/boe)	(0.66)	(0.43)	(5.55)	(0.43)	(9.13)
Royalties	($/boe)	(0.98)	(2.41)	(2.94)	(1.86)	(2.42)
Diluent costs	($/boe)	(1.09)	(1.85)	(2.22)	(1.69)	(1.92)
Net sales realized price (3)	($/boe)	56.22	53.21	49.35	56.15	51.26
Production costs (4)	($/boe)	(13.76)	(11.60)	(12.76)	(11.99)	(12.51)
Transportation costs (5)	($/boe)	(12.84)	(12.00)	(12.89)	(12.51)	(12.77)
Operating netback (6)	($/boe)	29.62	29.61	23.70	31.65	25.98
Financial Results						
Oil and gas sales and other revenue	($M)	356,922	289,641	277,944	1,351,071	1,368,227
Realized loss on risk management contracts	($M)	(4,006)	(2,135)	(25,667)	(9,720)	(192,970)
Royalties	($M)	(5,904)	(12,051)	(13,597)	(41,770)	(51,221)
Diluent costs	($M)	(6,581)	(9,238)	(10,291)	(38,064)	(40,544)
Net sales (6)	($M)	340,431	266,217	228,389	1,261,517	1,083,492
Net income (loss) (7)	($M)	69,408	(49,117)	(116,631)	294,287	(259,083)
Per share – basic	($)	0.71	(0.50)	(1.17)	3.01	(2.59)
Per share – diluted	($)	0.70	(0.50)	(1.17)	2.96	(2.59)
General and administrative	($M)	22,897	18,476	21,839	76,072	93,022
Operating EBITDA (6)	($M)	137,052	124,586	109,471	586,158	412,802
Cash provided by operating activities (8)	($M)	151,575	124,289	3,650	546,967	347,243
Capital expenditures (9)	($M)	132,452	70,761	156,400	345,919	446,083
Cash and cash equivalents – unrestricted	($M)	328,433	313,957	446,132	328,433	446,132
Restricted cash short and long-term	($M)	127,378	128,336	142,305	127,378	142,305
Total cash	($M)	455,811	442,293	588,437	455,811	588,437
Total debt and lease liabilities (10)	($M)	402,660	404,815	354,363	402,660	354,363

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 from 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 18. This section also includes a description and details for all per boe metrics included in operating netback.
7. Net income (loss) attributable to equity holders of the Company.
8. Prior periods' amounts have been revised to reflect the change in the accounting policy of interest paid as a financing activity instead of an operating activity. For further information on this adjustment, refer to Note 3b of the Consolidated Financial Statements.
9. Capital expenditures includes costs, net of income from exploration and evaluation ("**E&E**") assets.
10. Effective January 1, 2019, the Company adopted IFRS 16 - Leases ("**IFRS 16**"), which had a significant impact on reported results for 2019. The standard was adopted on a modified retrospective basis and therefore prior year information has not been restated and may not be comparable. Refer to Note 3b of the Consolidated Financial Statements.

Performance Highlights

Full Year 2019

- Net income was $294.3 million ($3.01/share), compared with a net loss of $259.1 million ($2.59/share) in 2018.
- Cash provided by operating activities was $547.0 million, compared with $347.2 million in 2018, contributing to a total cash position at December 31, 2019, of $455.8 million, including $127.4 million of restricted cash.
- Production averaged 70,875 boe/d, compared with 71,032 boe/d in 2018. Production exceeded the high-end of 2019 guidance of 65,000 to 70,000 boe/d.
- Operating EBITDA was $586.2 million, an increase of 42% compared with $412.8 million in 2018. The adoption of IFRS 16 increased operating EBITDA by $23.2 million, or 4%.
- Operating netback was $31.65/boe, an increase of 22% compared with $25.98/boe in 2018. The adoption of IFRS 16 increased operating netback by $0.74/boe, or 2%.
- Capital expenditures were $345.9 million, compared with $446.1 million in 2018, consistent with the midpoint of annual guidance.
- The Company has returned $143.4 million to shareholders, including $121.6 million (C$1.645/share) in dividends since the inception of its dividend policy and $21.8 million under its normal course issuer bid ("**NCIB**") program in share purchases during 2019.

Fourth Quarter 2019

- Net income of $69.4 million ($0.71/share), compared with a net loss of $116.6 million ($1.17/share) in the fourth quarter of 2018.
- Cash provided by operating activities of $151.6 million, compared with $3.7 million in the fourth quarter of 2018.
- Production averaged 70,905 boe/d, compared with 71,924 boe/d in the fourth quarter of 2018, and 70,213 boe/d in the previous quarter of 2019.
- Operating EBITDA of $137.1 million was 25% higher than the fourth quarter of 2018. The adoption of IFRS 16 increased operating EBITDA by $5.7 million, or 4%.
- Operating netback of $29.62/boe was 25% higher than $23.70/boe in the fourth quarter of 2018, and comparable to $29.61/boe in the previous quarter of 2019. The adoption of IFRS 16 increased operating netback by $0.72/boe, or 2%, in the fourth quarter of 2019.
- Capital expenditures were $132.5 million, compared to $156.4 million in the fourth quarter of 2018.
- The Company declared its regular quarterly dividend of C$0.205/share, or $15.1 million, which was paid on January 17, 2020, and purchased 1,548,814 shares for $11.9 million under its NCIB program.

Oil & Gas Reserves

- As at December 31, 2019, the Company reported proved plus probable reserves of 157.7 MMboe on a net basis, resulting in a reserves replacement ratio of 112% from the previous year's production. P2 reserves increased 2.8 MMboe, or 6%, compared with 2018 while proved net reserves remained stable at 104.8 MMboe. 1P reserves now represent 66% of the 2P reserves, compared with 68% in 2018.

3. GUIDANCE

The Company's 2019 financial and operational results were near the favorable end of all revised annual guidance metrics, with the exception of capital expenditures which came in below the midpoint. The Company had previously raised its 2019 Guidance range on July 31, 2019, for Operating EBITDA by 29% while reducing the range for production costs by 6%, both at the midpoint due to strong results from the first half of 2019, primarily from cost efficiencies, improved oil price differential assumptions and the impact of a weaker COP relative to previous estimates. The year-end results continue to demonstrate the Company's ability to deliver stable production with ongoing focus on cost reductions and efficiency improvements throughout the business.

In 2019, production averaged 70,875 boe/d above the high end of the guidance range of 65,000 to 70,000 boe/d. Higher production in Colombia driven by strong results from the heavy oil business unit was partially offset by lower production from Block 192 in Peru, as a result of increased downtime on the NorPeruano pipeline throughout the year.

Production costs of $11.99/boe were slightly below the low end of 2019 guidance of $12.00/boe to $12.50/boe as a result of the Company's cost reduction and efficiency improvement initiatives. Transportation costs of $12.51/boe also came in at the low end of guidance of $12.50/boe to $13.50/boe as a result of higher production volumes. In addition, production and transportation costs benefited from the depreciation of the COP against the USD.

Operating EBITDA in 2019 totaled $586 million, above the high end of 2019 guidance of $525 million to $575 million, as a result of higher production volumes, lower costs, and better than expected realized oil price differentials.

Capital expenditures totaled $346 million in 2019, just below the midpoint of guidance, and included the consolidation impact of capital expenditures related to CGX Energy Inc. ("**CGX**") (net impact of $16 million), which was not considered in the guidance for 2019.

		2019		2020
		Actual	**Guidance (1)**	**Guidance (2)**
Average production	(boe/d)	70,875	65,000 to 70,000	60,000 to 65,000
Average net production	(boe/d)	64,746	60,000 to 65,000	—
Production costs	($/boe)	11.99	12.00 to 12.50	11.50 to 12.50
Transportation costs	($/boe)	12.51	12.50 to 13.50	12.50 to 13.50
Operating EBITDA	($MM)	586	525 to 575	400 to 450
Capital expenditures (3)	($MM)	346	325 to 375	325 to 375

1. The 2019 guidance assumes $65.00/bbl Brent, realized oil price differentials of $3.50/bbl and a foreign exchange rate of 3,100 COP to 1 USD.
2. The 2020 guidance assumes $60.00/bbl Brent, realized oil price differentials of $4.00/bbl and a foreign exchange rate of 3,300 COP to 1 USD.
3. Includes Frontera's estimate of its share of costs of the 2020 Guyana exploration program, as joint venture partner, but does not include the consolidation impact of CGX's share of those exploration costs.

4. PROVED AND PROBABLE OIL AND GAS RESERVES

For the year ended December 31, 2019, the Company received independent certified reserves evaluation reports ("**Reserves Reports**") for all of its assets, with total net 2P reserves of 157.7 MMboe compared with 154.9 MMboe certified reserves in 2018. The year-over-year change was mainly caused by annual production, technical revisions and extensions in Quifa SW, Hamaca and other fields and discoveries in Sabanero and Mapache blocks. Proved net reserves of 104.8 MMboe now represent 66% of the total 2P reserves compared with 68% of the total 2P reserves in 2018.

The Reserves Reports were prepared in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation 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 at December 31, 2019 (Mmboe [1] [6])								
Country	Field	Proved (P1)		Probable (P2)		Proved + Probable (2P)		Hydrocarbon Type
		Gross	Net	Gross	Net	Gross	Net	
Colombia	Quifa SW block	57.7	50.3	4.2	3.6	61.9	53.9	Heavy oil
	Other heavy oil blocks [2]	28.7	27.3	26.1	25.7	54.8	53.0	Heavy oil
	Light/medium oil blocks [3]	26.7	24.9	19.4	18.0	46.1	42.8	Light and medium oil, associated natural gas
	Natural gas blocks [4]	1.7	1.7	0.7	0.7	2.4	2.4	Natural gas
	Sub-total	**114.7**	**104.2**	**50.5**	**48.0**	**165.2**	**152.1**	Oil and natural gas
Peru	Light/medium oil and natural gas blocks [5]	0.7	0.6	5.3	5.0	6.0	5.6	Light and medium oil, associated natural gas
	Total as at Dec. 31, 2019	**115.4**	**104.8**	**55.8**	**53.0**	**171.2**	**157.7**	Oil and natural gas
	Total as at Dec. 31, 2018	115.8	104.9	54.8	50.1	170.6	154.9	
	Difference	(0.4)	(0.1)	1.0	2.8	0.6	2.7	
	2019 Production	25.8	23.4	**Total reserves incorporated**		26.4	26.2	

1. See “Boe conversion” in the “Further Disclosures” section on page 27.
2. Includes Cajua, Sabanero and CPE-6 Blocks.
3. Includes Cubiro, Cravoviejo, Canaguaro, Guatiquia, Casimena, Corcel, Neiva, Cachicamo, Guaduas and other producing blocks.
4. Includes La Creciente block.
5. Includes onshore Block 192 and offshore Block Z1.
6. 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 production before royalties from the Company’s producing fields in Colombia and Peru. Refer to the “Further Disclosures” section on page 27 for details of the Company’s net production.

	Production (in boe/d)				
				Year ended December 31	
Producing blocks in Colombia	**Q4 2019**	**Q3 2019**	**Q4 2018**	**2019**	**2018**
Heavy oil	32,586	33,906	29,844	32,412	28,888
Light and medium oil	25,931	27,514	29,843	28,812	29,787
Natural gas	2,224	2,283	3,263	2,401	4,186
Total production Colombia	**60,741**	**63,703**	**62,950**	**63,625**	**62,861**
Producing blocks in Peru					
Light and medium oil	10,164	6,510	8,974	7,250	8,171
Total production Peru	**10,164**	**6,510**	**8,974**	**7,250**	**8,171**
Total production	**70,905**	**70,213**	**71,924**	**70,875**	**71,032**

Colombia

Production in Colombia for the year ended December 31, 2019, increased by 1% to 63,625 boe/d, compared to the prior year. Higher production was a result of heavy oil unit growth, mainly in the Quifa, CPE-6 and Sabanero blocks, as a result of development drilling, improved reservoir management and facilities optimization. This was offset by a reduction in the natural gas and light and medium oil units due to natural decline and water injection restrictions in the Casimena block.

In comparison to the fourth quarter of 2018, production was 4%, or 2,209 boe/d, lower during the fourth quarter of 2019. The decrease was primarily due to natural decline in some of the Company’s mature fields in light and medium oil, and natural gas blocks, mainly in the Guatiquia Block.

In comparison to the third quarter of 2019, production was 5%, or 2,962 boe/d, lower during the fourth quarter of 2019. This reflected the impact of downtime due to weather events, which resulted in power outages in the heavy oil business unit and reduced drilling activity in light and medium oil and natural gas business units.

Peru

For the year ended December 31, 2019, production decreased by 11%, to 7,250 boe/d, from 8,171 boe/d in the prior year. Production in Peru for the fourth quarter of 2019 averaged 10,164 boe/d, an increase of 13%, or 1,190 boe/d, compared with the same quarter of 2018. Production levels in Peru continue to be unpredictable and are primarily correlated with the number of operational days for the NorPeruano Pipeline. The number of operational days have fluctuated significantly as force majeure events on the pipeline have caused the Company to intermittently suspend production from the block.

In comparison to the third quarter of 2019, production was 56%, or 3,654 boe/d higher during the fourth quarter of 2019, reflecting greater pipeline operational stability and longer periods of production from Block 192. The service contract relating to Block 192 has been extended by six months by Perupetro S.A, Peru's state oil and gas company ("**Perupetro**") and is now expected to expire on September 2, 2020.

Production Reconciled to Sales Volumes

The following table reconciles the Company's average production to net production after payment of in-kind royalties and describes other factors that impacted total sales volumes.

					Year ended December 31	
		Q4 2019	Q3 2019	Q4 2018	2019	2018
Production	**(boe/d)**	**70,905**	**70,213**	**71,924**	**70,875**	**71,032**
Royalties in-kind Colombia	(boe/d)	(4,584)	(4,936)	(6,702)	(5,007)	(6,660)
Royalties in-kind Peru (1)	(boe/d)	(1,631)	(1,006)	(1,324)	(1,122)	(1,185)
Net production	**(boe/d)**	**64,690**	**64,271**	**63,898**	**64,746**	**63,187**
Oil inventory drawn (build)	(boe/d)	3,941	(8,694)	(5,797)	(619)	(3,079)
(Settlement) overlift positions (2)	(boe/d)	(19)	41	(8,792)	2	(768)
Sales volumes from E&E assets (3)	(boe/d)	(33)	(32)	(911)	(41)	(988)
Other inventory movements (4)	(boe/d)	(2,770)	(1,208)	1,900	(2,527)	(440)
Sales volumes	**(boe/d)**	**65,809**	**54,378**	**50,298**	**61,561**	**57,912**
Oil sales volumes	(bbl/d)	63,638	52,098	47,058	59,221	53,748
Natural gas sales volumes	(boe/d)	2,171	2,280	3,240	2,340	4,164
Inventory balance						
Colombia	(bbl)	904,648	798,953	716,893	904,648	716,893
Peru	(bbl)	1,382,754	1,851,080	1,344,626	1,382,754	1,344,626
Inventory ending balance	**(bbl)**	**2,287,402**	**2,650,033**	**2,061,519**	**2,287,402**	**2,061,519**

1. The Company reports the share of production retained by Peru government as royalties paid in-kind. Refer to the "Peru Royalties - Block 192 Contract" section on page 8.
2. Refer to the "Further Disclosures" section on page 27.
3. Volumes from E&E assets are excluded from total sales volumes, as the related revenue and costs are capitalized under IFRS.
4. Mainly corresponds to operational consumption and quality volumetric compensation.

Oil and gas sales volumes for the three months and year ended December 31, 2019, were higher than the same periods of 2018 and prior quarter of 2019, as the Company resumed sales in Peru in the fourth quarter of 2019. Despite lower production in Peru for the year ended December 31, 2019, higher sales were realized due to the drawdown of inventory volumes. In Colombia, higher inventory was due to the timing of cargo shipments.

Colombia Royalties - PAP

The Company makes high-price clause participation ("**PAP**") payments to Ecopetrol S.A. and the 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 once accumulated production has exceeded 5 MMbbl (commercial area for the Quifa block and exploitation area for exploration and production contracts) and escalates as oil prices increase above a minimum contractual baseline WTI price, which is adjusted yearly by the U.S. Producer Price Index. Increases in oil prices can trigger higher PAP obligations, payable both in-kind (reducing the Company's net production) and in cash (increasing royalties).

		Three months ended December 31		Year ended December 31	
		2019	2018	2019	2018
PAP in cash	(bbl/d)	926	1,359	1,239	1,649
PAP in kind	(bbl/d)	168	2,405	408	2,115
PAP	**(bbl/d)**	**1,094**	**3,764**	**1,647**	**3,764**
% Production		**1.5%**	**5.2%**	**2.3%**	**5.3%**

For the three months and year ended December 31, 2019, PAP decreased by 2,670 bbl/d and 2,117 bbl/d, respectively, due to lower WTI oil benchmark prices and lower production in Guatiquia block during the fourth quarter 2019.

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, Perupetro owns the volumes produced, 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, 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 at December 31, 2019, the Company has received in-kind payments for its services equivalent to 83% of the production from the block, with the balance being retained by Perupetro. Perupetro retained in-kind volumes averaging 1,631 bbl/d, during the three months ended December 31, 2019, compared with 1,324 bbl/d in the same period of 2018.

Realized and Reference Prices

					Year ended December 31	
		Q4 2019	**Q3 2019**	**Q4 2018**	**2019**	**2018**
Reference price						
Brent	($/bbl)	62.42	62.03	68.60	64.16	71.69
Average realized prices						
Realized oil price	($/bbl)	60.19	59.53	62.15	61.61	67.19
Realized natural gas price	($/boe)	20.04	18.57	25.90	19.21	24.09
Other revenue	($/boe)	0.08	0.09	0.24	0.13	0.64
Net sales realized price						
Oil and gas sales and other revenue	($/boe)	58.95	57.90	60.06	60.13	64.73
Realized loss on risk management contracts	($/boe)	(0.66)	(0.43)	(5.55)	(0.43)	(9.13)
Royalties	($/boe)	(0.98)	(2.41)	(2.94)	(1.86)	(2.42)
Diluent costs	($/boe)	(1.09)	(1.85)	(2.22)	(1.69)	(1.92)
Net sales realized price	**($/boe)**	**56.22**	**53.21**	**49.35**	**56.15**	**51.26**

Average Brent crude oil benchmark prices for the fourth quarter and year ended December 31, 2019, were lower compared with the same periods of 2018. The reduction in global crude oil prices was mostly attributable to a weaker global economic outlook arising from the trade war between the U.S. and China and lower manufacturing and industrial output. This was partially offset by the realization of narrower price differentials for the Company’s Vasconia blend, as the regional market remains short on heavy grade crude oil following U.S. sanctions on Venezuela and tariffs imposed by China on oil imports coming from the U.S.

For the fourth quarter and year ended December 31, 2019, the Company’s net sales realized price increased by 13.9% and 9.5%, respectively, compared to the same periods of 2018. This increase was primarily due to lower realized losses on risk management contracts and royalties per boe as a result of the decline in global oil prices, and stronger Vasconia differentials.

In comparison to the third quarter of 2019, the Company’s net sales realized price increased by $3.01/boe, or 5.7%, driven by slightly higher oil prices and lower royalties and diluent costs. Royalties were $1.43/boe, or 59.3% lower than the prior quarter due to a decrease in Guatiquia block production. Diluent cost were $0.76/boe, or 41.1% lower than the prior quarter as a result of higher heavy oil volumes transported by truck which does not require diluent.

Operating Netback

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

	Q4 2019		Q3 2019		Q4 2018	
	$M	($/boe)	$M	($/boe)	$M	($/boe)
Net sales realized price (1)	340,431	56.22	266,217	53.21	228,389	49.35
Production costs (2)	(89,789)	(13.76)	(74,939)	(11.60)	(84,441)	(12.76)
Transportation costs (3)	(76,428)	(12.84)	(70,960)	(12.00)	(75,748)	(12.89)
Operating Netback (4)	**174,214**	**29.62**	**120,318**	**29.61**	**68,200**	**23.70**
		(boe/d)		(boe/d)		(boe/d)
Sales volumes (D&P) (5)		65,809		54,378		50,298
Production (6)		70,905		70,213		71,924
Net production (7)		64,690		64,271		63,898

1. Per boe is calculated using sales volumes from 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. Refer to the "Other Selected Operating Costs" section on page 11 for fees that are not included in table.
4. Refer to the "Non-IFRS Measures" section on page 18 for details and a description of the operating netback calculation.
5. Sales volumes D&P assets exclude volumes from E&E assets as the related sales and costs are capitalized under IFRS.
6. Refer to the "Production" section on page 6.
7. Refer to the "Further Disclosures" section on page 27.

Operating netback for the fourth quarter of 2019 was $29.62/boe, compared to $23.70/boe in the same quarter of 2018. The increase was primarily due to a higher net sales realized price of $6.87/boe, which was partially offset by higher production costs. The increase in production costs per boe was primarily the result of higher well services and workovers on the Guatiquia and Cravoviejo blocks, additional field maintenance operations and social investments in communities on Block 192 in Peru. The operating netback in the fourth quarter of 2019 was comparable to the previous quarter of 2019.

The following table provides a summary of the Company's year operating netbacks:

	Year ended December 31			
	2019		2018	
	$M	($/boe)	$M	($/boe)
Net sales realized price (1)	1,261,517	56.15	1,083,492	51.26
Production costs (2)	(310,084)	(11.99)	(324,400)	(12.51)
Transportation costs (3)	(295,554)	(12.51)	(294,471)	(12.77)
Operating Netback (4)	**655,879**	**31.65**	**464,621**	**25.98**
		(boe/d)		(boe/d)
Sales volumes (D&P) (5)		61,561		57,912
Production (6)		70,875		71,032
Net production (7)		64,746		63,187

References 1 through 7 are consistent with those included in the quarterly Operating Netback table above.

Operating netback for the year ended December 31, 2019, increased by 22% to $31.65/boe, from $25.98/boe in 2018. The increase was consistent with a higher net sales realized price of $4.89/boe and lower production costs per boe mainly due to a reduction in contractor field services and lower maintenance activities in Peru.

Sales

	Three months ended December 31		Year ended December 31	
($M)	2019	2018	2019	2018
Oil and gas sales and other revenue (1)	356,922	277,944	1,351,071	1,368,227
Realized loss on risk management contracts	(4,006)	(25,667)	(9,720)	(192,970)
Royalties	(5,904)	(13,597)	(41,770)	(51,221)
Diluent costs	(6,581)	(10,291)	(38,064)	(40,544)
Net sales	**340,431**	**228,389**	**1,261,517**	**1,083,492**
$/boe using sales volumes from D&P assets	56.22	49.35	56.15	51.26

1. In Colombia, for the year ended December 31, 2019, oil and gas sales and other revenue were $1.22 billion compared with $1.24 billion in the same period of 2018. In Peru, for the year ended December 31, 2019, oil and gas sales and other revenue were $135.1 million, compared with $128.5 million in the same period of 2018.

Oil and gas sales and other revenue for the three months ended December 31, 2019, increased by $79.0 million compared to the same period in 2018, mainly due to higher oil volumes sold. For the year ended December 31, 2019, oil and gas and other revenue decreased by $17.2 million compared with the prior year as a result of lower oil prices, which offset higher sales volumes year-over-year.

Net sales for the three months and year ended December 31, 2019, increased by $112.0 million and $178.0 million, respectively, compared with the same periods in 2018. The following table describes the various factors that impacted net sales:

	Three months ended December 31	Year ended December 31
($M; FY analysis in parenthesis)	**2019-2018**	**2019-2018**
Net sales for the period ended December 31, 2018	228,389	1,083,492
Lower realized loss on risk management contracts	21,661	183,250
Increase due to higher volumes sold of 15,511 boe/d or 31% (FY 3,649 boe/d or 6% higher)	84,120	80,086
Decrease in royalties	7,693	9,451
Decrease in diluent costs	3,710	2,480
Decrease due to 2% lower oil and gas price (FY 7% lower)	(5,142)	(97,242)
Net sales for the period ended December 31, 2019	**340,431**	**1,261,517**

Royalties

	Three months ended December 31		Year ended December 31	
($M)	**2019**	**2018**	**2019**	**2018**
Royalties Colombia	5,721	13,327	41,023	50,253
Royalties Peru	183	270	747	968
Royalties	**5,904**	**13,597**	**41,770**	**51,221**
$/boe using sales volumes from D&P assets	0.98	2.94	1.86	2.42

Royalties include cash payments for PAP, royalties and amounts paid to previous owners of certain blocks in Colombia. For the three months and year ended December 31, 2019, royalties decreased by $7.7 million and $9.5 million, respectively, compared to the same periods in 2018. The decrease in royalties in the fourth quarter was primarily due to lower production from the Guatiquia block combined with lower WTI oil benchmark prices. For the year ended December 31, 2019, the decrease was mainly related to the impact from lower WTI oil benchmark prices. The Company's royalty burden is directly correlated with changes in WTI oil benchmark prices due to the price sensitivity of PAP in Colombia. Refer to the "Production Reconciled to Sales Volumes" section on page 7 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)	**2019**	**2018**	**2019**	**2018**
Production costs	89,789	84,441	310,084	324,400
Transportation costs	76,428	75,748	295,554	294,471
Diluent costs	6,581	10,291	38,064	40,544
Overlift (settlement)	353	(59,693)	512	(16,961)
Inventory valuation	13,318	(12,266)	(7,628)	(33,265)
Total oil and gas operating costs	**186,469**	**98,521**	**636,586**	**609,189**

For the three months and year ended December 31, 2019, total oil and gas operating costs increased compared to the same periods in 2018 due to the following:

- Production costs in the fourth quarter of 2019 were 6.3% higher than the same quarter of 2018 mainly due to higher well services, workovers, and maintenance expenditures in Colombia and social investments in communities on Block 192 in Peru. For the year ended December 31, 2019, production costs decreased by 4.4% compared with 2018 as a result of savings from cost optimization programs, reductions in contractor field services and lower maintenance activities in Peru.
- Transportation costs in the three months and year ended December 31, 2019, was relatively consistent with the same prior year periods, as an increase from higher volumes sold in Peru was offset by the adoption of IFRS 16. Transportation costs include $33.1 million or $1.40/boe in 2019 (2018: $14.9 million or $0.65/boe) related to existing take-or-pay contracts for ancillary facilities after the termination of transportation agreements in 2018 for further information refer to the "Commitments and Contractual Obligations" section on page 21.

- Diluent costs decreased by 36.1% and 6.1% for the three months and year ended December 31, 2019, respectively, compared with the same periods of 2018. The decrease in diluent costs was mainly related to higher heavy oil volumes transported by truck which does not require diluent, and favorable natural gasoline market conditions for blending during 2019.
- The Company did not have significant overlift or settlements during 2019 compared to $59.7 million and $17.0 million in settlements of overlift balances in the fourth quarter and year ended December 31, 2018, respectively.
- Inventory valuation for the three months and year ended December 31, 2019, increased by $25.6 million and $25.6 million, respectively, due to sales in the fourth quarter of the inventory build up in Peru, partially offset by higher ending inventories in Colombia.

Other Selected Operating Costs

	Three months ended December 31		Year ended December 31	
($M)	**2019**	**2018**	**2019**	**2018**
Fees paid on suspended pipeline capacity	—	—	—	82,372
Payments under terminated pipeline contracts	—	59,040	—	74,618
Reversal of provision related to PAP	—	(41,079)	—	(62,911)

The Company did not incur fees paid on suspended pipeline capacity or payments under terminated pipeline capacity in 2019 due to the termination of the transportation contracts with Oleoducto Bicentenario de Colombia S.A.S. ("**Bicentenario**") and Cenit Transporte y Logistica de Hidrocarburos S.A.S. ("**CENIT**") in July 2018.

During 2018, the Company recognized the reversal of provisions related to the PAP on certain blocks. The provisions were reversed as an external legal opinion supported the Company's technical interpretation of the relevant contracts.

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

General and Administrative

	Three months ended December 31		Year ended December 31	
($M)	**2019**	**2018**	**2019**	**2018**
General and administrative	22,897	21,839	76,072	93,022

For the three months ended December 31, 2019, general and administrative expenses increased by 5%, compared to the same period in 2018, primarily due to the impact from a short-term employee incentive program implemented during the fourth quarter of 2019. General and administrative expenses for the year ended December 31, 2019, decreased by 18% compared to 2018 mainly from cost efficiencies, lower employee-related costs from the Company's organizational restructuring and lower office lease costs of $5.8 million due to the adoption of IFRS 16.

Depletion, Depreciation and Amortization

	Three months ended December 31		Year ended December 31	
($M)	**2019**	**2018**	**2019**	**2018**
Depletion, depreciation and amortization	89,753	80,461	376,010	316,751

Depletion, depreciation and amortization expense ("**DD&A**") increased by 12% and 19% for the three months and year ended December 31, 2019, respectively, compared to the same periods in 2018. The increase in DD&A was due to higher oil production in Colombia and a higher depreciable base resulting from an increase in future capital cost estimates, and the recognition of $64.1 million in right-of-use ("**ROU**") assets on the adoption of IFRS 16. Also, effective April 1, 2019, the Company acquired transportation capacity rights on the Oleoducto Central S.A. pipeline for $68.6 million, which are being amortized over five years using the straight-line method. For the year ended December 31, 2019, the incremental DD&A relating to the ROU assets and the transportation rights was $24.5 million and $10.3 million, respectively.

Impairment, Exploration Expenses and Other

($M)	Three months ended December 31		Year ended December 31	
	2019	2018	2019	2018
Impairment of other assets	—	—	36,628	—
Impairment of exploration and evaluation assets	1,838	67,132	19,526	93,874
Impairment of properties plant and equipment	—	13,899	—	18,685
Impairment of investment in associates	—	47,816	—	189,988
Impairment of assets held for sale - transmission line assets	—	—	—	9,125
Other impairment	—	4,064	4,745	9,808
Total impairment	**1,838**	**132,911**	**60,899**	**321,480**
Exploration expenses	595	8,927	3,658	9,706
Expense (recovery) of asset retirement obligations	1,551	(15.894)	2,681	(15.894)
Total impairment, exploration expenses and other	**3,984**	**125,944**	**67,238**	**315,292**

For the year ended December 31, 2019, the Company recognized an impairment charge on other assets of $36.6 million related to a long-term receivable from Infrastructure Ventures Inc. ("**IVI**") as a result of uncertainties relating to future projects and a reduction in future cash flows at the port subsidiary of IVI, Sociedad Portuaria Puerto Bahía S.A. ("**Puerto Bahia**").

For the year ended December 31, 2019, an impairment charge of $19.5 million was recognized regarding certain E&E assets from the Colombian Cash Generating Units, as it was determined that the carrying value of the assets will not be recoverable in future periods. This was lower than $93.9 million of impairment charges taken on E&E assets during 2018.

For the year ended December 31, 2018, the Company recognized impairment charges totalling $190.0 million on its equity investments in associates Bicentenario, IVI, and Interamerican Energy Corp. ("**Interamerican**"). The investments in Bicentenario and IVI were written-down to their recoverable amounts based on value-in-use calculations using a discounted dividend cash flow model, whereas the carrying value of the investment in Interamerican was higher than its fair value less costs to sell as implied by a bid offer.

Restructuring, Severance and Other Costs

($M)	Three months ended December 31		Year ended December 31	
	2019	2018	2019	2018
Restructuring	—	2,177	—	4,495
Severance and other costs	2,994	5,915	11,945	10,097
Total restructuring, severance and other costs	**2,994**	**8,092**	**11,945**	**14,592**

Restructuring, severance and other costs for the three months and year ended December 31, 2019, were lower by $5.1 million and $2.6 million, respectively, compared with the same periods in 2018 primarily due to higher severance charges from personnel reductions in the prior year. During 2019, the Company incurred costs related to a new organizational restructuring plan to improve processes and generate further operational efficiencies.

Non-Operating Costs

($M)	Three months ended December 31		Year ended December 31	
	2019	2018	2019	2018
Finance income	3,162	7,581	20,244	25,832
Finance expenses	(17,438)	(14,668)	(65,492)	(52,724)
Foreign exchange loss	(8,812)	(13,087)	(10,264)	(3,375)
Other (loss) income, net	(6,680)	(832)	2,758	(4,741)

Finance Income and Expenses

Finance income decreased by 58% and 22%, respectively, for the three months and year ended December 31, 2019, compared to the same periods of 2018, as a result of lower average cash balances. For the three months and year ended December 31, 2019, finance expenses increased to $17.4 million and $65.5 million, respectively, primarily due to interest on lease liabilities recognized on the adoption of IFRS 16.

Foreign Exchange Loss

For the three months and year ended December 31, 2019, the Company recognized a foreign exchange loss of $8.8 million and $10.3 million, compared to $13.1 million and $3.4 million, respectively, in the same periods of 2018, primarily due to the impact of the COP's depreciation against the USD on the translation of the Company's net working capital balances in COP.

Other (Loss) Income, net

For the year ended December 31, 2019, other income was $2.8 million compared to other loss of $4.7 million in 2018, mainly due to a gain of $10.9 million resulting from the fair value equity adjustment on the acquisition of CGX in the first quarter of 2019, partially offset by an increase in penalties and litigation expenses. For the three months ended December 31, 2019, the Company reported other loss of $6.7 million, which included the recognition of environmental contingencies.

(Loss) Gain on Risk Management Contracts

	Three months ended December 31		Year ended December 31	
($M)	**2019**	**2018**	**2019**	**2018**
Realized loss on risk management contracts [1]	(4,006)	(25,667)	(9,720)	(192,970)
Unrealized (loss) gain on risk management contracts [2]	(10,333)	31,392	(5,722)	107,337
Total (loss) gain on risk management contracts	**(14,339)**	**5,725**	**(15,442)**	**(85,633)**

1. Represents risk management contracts that have settled during the period.
2. Represents the mark-to-market change in the fair value of outstanding contracts and the reversal of prior unrealized amounts on contracts that settled in the period.

For the three months and year ended December 31, 2019, realized loss on risk management contracts was $4.0 million and $9.7 million, respectively. This was significantly lower than the same prior year periods of 2018, primarily as a result of differences in the underlying hedging instruments that expired or settled during each period. During 2019, Brent oil put options expired (which limited the loss to the premiums paid) compared to 2018 when zero cost collars were settled at oil prices that were significantly higher than average ceiling contract prices. For further information refer to the risk management strategy described in the section "Risk Management Contracts - Brent Crude Oil" below.

For the three months and year ended December 31, 2019, the Company recognized an unrealized loss on risk management contracts of $10.3 million and $5.7 million, respectively, due to the decrease in the crude oil benchmark forward prices over the contract periods. This is compared to an unrealized gain of $31.4 million and $107.3 million, respectively, in the same prior year periods, primarily related to the reversal of prior unrealized amounts, as zero cost collars settled during the period.

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. Consistent with the Company's risk management goals and priorities, the hedging strategy is designed to protect the Company's capital program and debt service requirements. In 2019, the Company executed a risk management strategy using a layered approach primarily with put options to protect against downward price movements while retaining the opportunity to realize the upside from rising prices, in contrast to 2018 when the Company only used zero cost collars. For 2020, the Company has added a mix of derivatives instruments (Collars, 3 - Ways, Puts and Put Spreads) to its hedging program.

				Avg. Strike Prices	Carrying Amount ($M)	
Type of Instrument	**Term**	**Benchmark**	**Notional Amount / Volume (bbl)**	**Put / Call; Call Spreads $**	**Assets**	**Liabilities**
Put options	January to March 2020	Brent	964,000	58.75	357	—
Zero cost collars	January to March 2020	Brent	1,389,000	58.10 / 73.75	486	36
3-ways	April to September 2020	Brent	3,567,000	48.60/58.60/74.50	5,590	—
Put Spread	January to December 2020	Brent	1,890,000	48.10/58.10	908	—
Total as at December 31, 2019					**7,341**	**36**
Put options	January to September 2019	Brent	2,220,000	55.00	9,380	—
Total as at December 31, 2018					**9,380**	**—**

Risk Management Contracts - Foreign Exchange

The Company is exposed to foreign currency fluctuations. 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, 2019, the Company has entered into foreign currency derivatives contracts from January to September 2020, for $204.0 million (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 $M**	**Avg. Put / Call; Par forward COP**	**Assets**	**Liabilities**
Zero cost collars	January to September 2020	COP / USD	$ 204,000	3,241 / 3,667	2,768	—
Total as at December 31, 2019					**2,768**	**—**
Zero cost collars	January to June 2019	COP / USD	$ 172,500	3,032 / 3,273	—	3,299
Forward	January to March 2019	COP / USD	$ 22,500	3,109	—	1,019
Total as at December 31, 2018					**—**	**4,318**

Income Tax Recovery (Expense)

	Three months ended December 31		Year ended December 31	
($M)	**2019**	**2018**	**2019**	**2018**
Current income tax expense	(4,974)	(5,937)	(42,645)	(30,507)
Deferred income tax recovery (expense)	47,514	(10,130)	190,372	11,786
Total income tax recovery (expense)	**42,540**	**(16,067)**	**147,727**	**(18,721)**

The current income tax expense for the fourth quarter of 2019 was $5.0 million, compared to $5.9 million in the same quarter of 2018, primarily due to a reduction in the presumptive tax rates applicable to the Company. For the year ended December 31, 2019, the current income tax expense of $42.6 million was $12.1 million higher than 2018, due to a charge of $27.1 million relating to changes in old income tax assessments in Colombia which, offset the lower presumptive tax rates.

The deferred income tax recovery for the fourth quarter of 2019 was $47.5 million, compared to an expense of $10.1 million in the same quarter of 2018. For the year ended December 31, 2019, the deferred income tax recovery was $190.4 million, compared to $11.8 million in 2018. The increase in both periods was primarily due to the recognition of higher deferred tax assets in Colombia to reflect changes in the tax legislation and the Company's assessment that sufficient future taxable profits will be available against which deductible temporary differences and the carry-forward of unused tax credits and losses can be utilized.

Net Income (Loss)

	Three months ended December 31		Year ended December 31	
($M)	**2019**	**2018**	**2019**	**2018**
Net income (loss) attributable to equity holders of the Company	69,408	(116,631)	294,287	(259,083)
Per share – basic ($)	0.71	(1.17)	3.01	(2.59)
Per share – diluted ($)	0.70	(1.17)	2.96	(2.59)

For the year ended December 31, 2019, the Company reported a net income of $294.3 million, which includes $141.4 million of operating income and a tax recovery of $147.7 million from the recognition of deferred tax assets in Colombia. This compared to a net loss of $259.1 million in 2018, primarily as a result of lower impairment charges of $248.1 million, higher deferred income tax recovery of $178.6 million, and no fees paid on suspended pipeline capacity or payments under terminated pipeline contracts, which totalled $157.0 million in 2018.

For the three months ended December 31, 2019, the Company reported a net income of $69.4 million compared to a net loss of $116.6 million in the same period of 2018, mainly due to the deferred income tax recovery of $47.5 million recognized in the fourth quarter of 2019 and higher operating income of $133.6 million driven by lower impairment charges and no payments under terminated pipeline contracts.

Capital Expenditures

($M)	Three months ended December 31 2019	Three months ended December 31 2018	Year ended December 31 2019	Year ended December 31 2018
Maintenance and development drilling	58,198	88,883	196,522	237,760
Exploration activities [(1)]	47,700	17,830	96,995	102,078
Facilities and infrastructure	22,982	46,262	46,288	96,302
Other	3,572	3,425	6,114	9,943
Total capital expenditures	**132,452**	**156,400**	**345,919**	**446,083**

1. Includes expenditures, net of income from E&E assets.

Capital expenditures for the year ended December 31, 2019, were 22% lower compared to the prior year primarily due to higher spending in 2018 on production facilities (such as the water handling expansion in Quifa) and higher cost on exploration wells. For the three months ended December 31, 2019, capital expenditures were 15% lower compared to the same prior year period primarily due to lower development drilling in Colombia and higher expenditures in the fourth quarter of 2018 on the completion of the facilities expansion in Quifa. These reductions were offset in the quarter by higher exploration spending on the seismic program in Guyana and new wells drilled in CPE-6 and VIM-1 blocks.

During the fourth quarter of 2019, the Company drilled 18 development wells and three exploration wells, compared to 25 development wells and three exploration wells in the fourth quarter of 2018. For the year ended December 31, 2019, the Company drilled 116 development wells and eight exploration wells, compared to 121 development wells and eight exploration wells drilled in 2018.

In Guyana, the Company along with its partner CGX, completed a 3D seismic program on the northern portion of the Corentyne offshore block. Reprocessing of the 3D data set is currently underway and completion is expected in the second quarter of 2020. The new 3D seismic data will facilitate the development of a high quality list of prospects and the selection of a drilling location on the Corentyne block during the second half of 2020. In addition, the Company and CGX plan to select and drill a commitment well in the Demerara block in the second half of 2020. In Colombia, testing results from the La Belleza-1 well on the VIM-1 block were positive and the Company, in conjunction with its exploration joint venture partner Parex Resources Inc., are evaluating options to drill one or two additional delineation wells in the second half of 2020 and analyzing different options for gas commercialization and infrastructure requirements.

Selected Quarterly Information

Operational and financial results		2019 Q4	2019 Q3	2019 Q2	2019 Q1	2018 Q4	2018 Q3	2018 Q2	2018 Q1
Oil production	(bbl/d)	68,681	67,930	71,931	65,323	68,661	62,271	67,522	68,983
Natural gas production	(boe/d)	2,224	2,283	2,454	2,651	3,263	4,122	4,504	4,875
Production	(boe/d)	70,905	70,213	74,385	67,974	71,924	66,393	72,026	73,858
Oil and gas natural gas sales volumes	(boe/d)	65,809	54,378	66,105	59,968	50,298	61,071	67,822	52,440
Brent price	($/bbl)	62.42	62.03	68.47	63.83	68.60	75.84	74.97	67.23
Oil and gas sales and other revenue	($/boe)	58.95	57.90	65.01	58.08	60.06	68.02	67.82	61.34
Realized loss on risk management contracts	($/boe)	(0.66)	(0.43)	(0.33)	(0.30)	(5.55)	(10.02)	(11.12)	(8.98)
Royalties	($/boe)	(0.98)	(2.41)	(2.40)	(1.74)	(2.94)	(2.83)	(2.19)	(1.74)
Diluent costs [(1)]	($/boe)	(1.09)	(1.85)	(2.17)	(1.71)	(2.22)	(1.89)	(1.74)	(1.88)
Net sales realized price	($/boe)	56.22	53.21	60.11	54.33	49.35	53.28	52.77	48.74
Production costs [(1)]	($/boe)	(13.76)	(11.60)	(11.17)	(11.40)	(12.76)	(13.84)	(12.44)	(11.11)
Transportation costs [(1)]	($/boe)	(12.84)	(12.00)	(12.49)	(12.70)	(12.89)	(13.77)	(11.81)	(12.68)
Operating netback [(1)]	($/boe)	29.62	29.61	36.45	30.23	23.70	25.67	28.52	24.95
Revenue	($M)	351,027	277,676	377,347	377,527	265,109	366,511	405,198	283,667
Net income (loss)	($M)	69,408	(49,117)	227,809	46,187	(116,631)	45,105	(184,436)	(3,121)
Per share – basic ($)	($)	0.71	(0.50)	2.32	0.47	(1.17)	0.45	(1.84)	(0.03)
Per share – diluted ($)	($)	0.70	(0.50)	2.29	0.47	(1.17)	0.45	(1.84)	(0.03)
General and administrative [(1)]	($M)	22,897	18,476	18,207	16,492	21,839	22,962	26,168	22,053
Operating EBITDA [(1)]	($M)	137,052	124,586	179,665	144,855	109,471	92,676	124,667	85,988
Capital expenditures	($M)	132,452	70,761	73,487	69,219	156,400	124,029	86,813	78,841

1. Effective January 1, 2019, the Company adopted IFRS 16 on a modified retrospective basis and therefore the 2018 quarters have not been restated and may not be comparable. Refer to Note 3b of the Consolidated Financial Statements.

Over the past eight quarters, the Company's sales have fluctuated due to changes in production, changes in inventory balances, timing of cargo shipments, movements in the Brent benchmark oil price and fluctuations in realized oil price differentials. The Company's production levels in Colombia have increased in heavy oil blocks partially offset by natural declines on light and medium oil blocks. The Company has had fluctuating production in Peru since operations at Block 192 have experienced periods of suspension under force majeure due to issues on the NorPeruano pipeline. Despite the decrease in production, sales in the fourth quarter of 2019 were higher due to inventory build up in previous periods. Trends in the Company's net income and loss are also impacted most significantly by deferred income tax, DD&A and net impairment charges of oil, gas and other assets, gains and losses from risk management activities that fluctuate with changes in hedging strategies and forward market prices.

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

Selected Annual Information

	As at and for the year ended December 31		
($M, except as noted)	**2019**	**2018**	**2017**
Revenue	1,383,577	1,320,485	1,254,425
Net income (loss) attributable to equity holders of the Company	294,287	(259,083)	(216,703)
Per share – basic ($) [(1)]	3.01	(2.59)	(2.17)
Per share – diluted ($) [(1)]	2.96	(2.59)	(2.17)
Cash and cash equivalents	328,433	446,132	511,685
Total assets [(2)]	2,492,751	2,291,278	2,579,651
Total non-current liabilities [(2)]	639,460	578,822	501,902
Total liabilities [(2)]	1,222,717	1,184,090	1,183,270

1. On June 26, 2018, the Company completed a two-for-one share split on its issued and outstanding Common Shares. As a result, the loss per share for 2017 is stated on an adjusted post-split basis.
2. Effective January 1, 2019, the Company adopted IFRS 16 on a modified retrospective basis and therefore 2018 and 2017 have not been restated and may not be comparable. Refer to Note 3b of the Consolidated Financial Statements.

Revenue increased to $1.38 billion in 2019 from $1.32 billion in 2018. The revenue increase was mainly due to higher trading and produced volumes sold and was partially offset by the reduction in global crude oil prices. In comparison with $1.25 billion revenue in 2017, the increase was primarily due to higher international crude oil prices.

Net income for 2019 was $294.3 million, compared to a net loss of $259.1 million in the same period of 2018 and a net loss $216.7 million for 2017, as a result of lower impairment charges, higher deferred income tax recovery, no fees paid on suspended pipeline capacity, no payments under terminated pipeline capacity and lower loss on risk management contracts.

Total assets have increased to $2.49 billion in 2019 from $2.29 billion in 2018 mainly as a result of the adoption of IFRS 16 and the acquisition of CGX and related exploration assets in Guyana. In comparison with $2.58 billion in 2017, total assets have decreased as a result of the Company's corporate strategy to monetizing certain non-core assets through divestment, and 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 an ending cash and cash equivalents position of $328.4 million. The reduction in total cash balances compared with previous years is a result of initiatives to enhance shareholder returns such as dividends and share repurchases.

Midstream Activities

The Company has investments in certain infrastructure and midstream assets. These assets include the Company's investments in pipelines, storage and other facilities relating to the distribution and exportation of crude oil products in Colombia. The Company's significant midstream assets are accounted for using the equity method of accounting, which requires that the carrying value of the investment be increased to reflect the Company's proportionate share of net income, or reduced to reflect its share of net losses and dividends declared. The following section provides a summary and update of these investments.

Pacific Midstream Limited ("PML")

The Company holds a 59.9% interest in PML, which has a 35% equity investment in Oleoducto de los Llanos Orientales S.A. ("**ODL**"). ODL owns the ODL pipeline, which connects from the Rubiales and Quifa fields to the Monterrey Station or Cusiana Station in Casanare Department.

For the year ended December 31, 2019, the Company's share of income from ODL increased by $3.0 million compared to the same period of 2018, primarily due to higher volumes transported in the Llanos region and the impact of foreign exchange fluctuations. During the year ended December 31, 2019, the Company recognized gross dividends of $52.8 million, which were declared and paid by ODL.

Bicentenario

The Company holds a 43.0% interest in Bicentenario, which owns the Bicentenario pipeline ("**BIC Pipeline**") that connects the Araguaney Station in the Casanare Department to the Banadia Station in the Arauca Department. At the Banadia Station, the BIC Pipeline connects to the Caño Limon Coveñas pipeline ("**CLC Pipeline**"), which connects to the Coveñas terminal on Colombia's Caribbean coastline in the Sucre Department.

On March 22, 2019, the Company increased its net ownership interest in Bicentenario from 26.4% to 43.0% through the acquisition of PML's ownership interest in Bicentenario for approximately $84.8 million. The International Financial Corporation and related funds exercised their right requiring the Company to purchase PML's interest in Bicentenario as a result of the termination of the Company's take or pay contracts with Bicentenario because the BIC Pipeline was non-operational for six consecutive months. The net cost of the acquisition to the Company was approximately $34.0 million after the proceeds of the transaction were distributed by PML to its shareholders, including the Company.

For the year ended December 31, 2019, the Company's share of income from Bicentenario decreased by $11.3 million compared to the same period of 2018 due to lower pipeline revenue after the termination of the Company's transportation contracts with Bicentenario in July 2018. For the year ended December 31, 2019, the Company recognized gross dividends of $34.4 million, which were declared but not paid by Bicentenario. As at December 31, 2019, the discounted carrying value of dividends receivable from Bicentenario increased to $39.1 million ($45.7 million undiscounted) from $14.4 million ($15.7 million undiscounted) as at December 31, 2018.

IVI (Formerly Pacific Infrastructure Ventures Inc.)

The Company holds a 39.2% interest in Puerto Bahia through its interest in IVI. Puerto Bahia operates a multipurpose port facility in the Bay of Cartagena. The port, which consists of a hydrocarbon terminal and a dry cargo terminal, is adjacent to the Bocachica access channel of the Cartagena Bay, and is strategically located near the Cartagena Refinery and the Panama Canal.

For the year ended December 31, 2019, the Company advanced $24.7 million under the terms of an equity contribution agreement (**"ECA"**) by way of shareholder loans directly to IVI's port subsidiary, Puerto Bahia (the "**Puerto Bahia ECA Loans**"). Under the ECA, the Company and IVI agreed to jointly and severally cause equity contributions (via debt or equity) to Puerto Bahia up to the aggregate amount of $130.0 million. Amounts advanced under the ECA are designated to the repayment of principal and interest from debt obligations of Puerto Bahia. The Puerto Bahia ECA Loans are subordinated to the Puerto Bahia bank debt facility and bear interest of 14%. To date, the Company has advanced a total of $65.9 million under the ECA with a carrying value including interest of $75.7 million.

For the year ended December 31, 2019, the Company's share of loss from IVI decreased by $6.9 million compared with 2018, mainly due to a lower unrealized loss on the revaluation of IVI's USD denominated debt. As the carrying amount of the Company's equity investment in IVI was reduced to $Nil at December 31, 2018, the share of losses during 2019 have been recorded as a reduction to other assets with IVI. As of December 31, 2019, the carrying value of the Company's net investment (which includes loans and long term receivables) in IVI has decreased to $98.2 million compared to $110.8 million due to the recognition of the equity method losses and an impairment charge of $36.6 million, partially offset by the advances under the ECA.

The Company's consolidated statement of cash flows ("**Consolidated Statement of Cash Flows**") and consolidated statement of financial position ("**Consolidated Statement of Financial Position**") includes the following amounts relating to midstream activities:

	Year ended December 31							
Statements of Cash Flows	**2019**				**2018**			
($M)	**ODL**	**Bicentenario [1]**	**IVI**	**Total**	**ODL**	**Bicentenario**	**IVI**	**Total**
Dividends received from associates	58,403	—	—	58,403	39,617	27,966	—	67,583
Dividends paid to NCI	(22,285)	—	—	(22,285)	(15,295)	(10,190)	—	(25,485)
Cash flow from midstream dividends	**36,118**	**—**	**—**	**36,118**	**24,322**	**17,776**	**—**	**42,098**
Puerto Bahia ECA Loans	—	—	(24,700)	(24,700)	—	—	(41,211)	(41,211)
Net cash flow from midstream investments	**36,118**	**—**	**(24,700)**	**11,418**	**24,322**	**17,776**	**(41,211)**	**887**

1. Excludes dividends paid to non-controlling interest related to the acquisition of PML's ownership interest in Bicentenario.

Statements of Financial Position	As at December 31, 2019				As at December 31, 2018			
($M)	**ODL**	**Bicentenario**	**IVI**	**Total**	**ODL**	**Bicentenario**	**IVI**	**Total**
Dividends receivable	—	39,081	—	39,081	9,047	14,447	—	23,494
Puerto Bahia ECA Loans	—	—	75,688	75,688	—	—	43,947	43,947
Puerto Bahia other loan and receivables	—	—	22,545	22,545	—	—	66,825	66,825
Long-term receivable [1]	**—**	**39,081**	**98,233**	**137,314**	**9,047**	**14,447**	**110,772**	**134,266**
Investment in associates (equity)	115,855	81,106	—	196,961	117,368	73,743	—	191,111
Net book value of midstream investments	**115,855**	**120,187**	**98,233**	**334,275**	**126,415**	**88,190**	**110,772**	**325,377**

1. Included as Other Assets.

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 are therefore 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.

Operating EBITDA

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

Operating EBITDA represents the operating results of the Company’s primary business, excluding the items noted above, fees paid on suspended pipeline capacity, payments under terminated pipeline contracts, restructuring, severance and other costs, certain non-cash items (such as impairments, foreign exchange, 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.

Beginning in the fourth quarter of 2019, the Company changed the composition of its Operating EBITDA calculation to include non-capital exploration expenditures as they are considered part of its normal course of operations. The Operating EBITDA for 2018 was revised to reflect this change, resulting in a reduction of $9.7 million from what was previously reported.

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

	Three months ended December 31		Year ended December 31	
($M)	**2019**	**2018**	**2019**	**2018**
Net income (loss)	69,408	(116,631)	294,287	(259,083)
Finance income	(3,162)	(7,581)	(20,244)	(25,832)
Finance expenses	17,438	14,668	65,492	52,724
Income tax (recovery) expense	(42,540)	16,067	(147,727)	18,721
Depletion, depreciation and amortization	89,753	80,461	376,010	316,751
Impairment	3,389	117,017	63,580	305,586
Fees paid on suspended pipeline capacity	—	—	—	82,372
Payments under terminated pipeline contracts	—	59,040	—	74,618
Reversal of provision related to high-price clause	—	(41,079)	—	(62,911)
Loss on extinguishment of debt	—	—	—	25,628
Reclassification of currency translation adjustments	—	(2,753)	—	48,094
Share-based compensation	(124)	166	2,907	4,042
Restructuring, severance and other costs	2,994	8,092	11,945	14,592
Share of income from associates	(24,398)	(8,952)	(84,832)	(83,601)
Foreign exchange loss	8,812	13,087	10,264	3,375
Unrealized loss (gain) on risk management contracts	10,333	(31,392)	5,722	(107,337)
Other loss (income), net	6,680	832	(2,758)	4,741
Non-controlling interests	(1,531)	8,429	11,512	322
Operating EBITDA	**137,052**	**109,471**	**586,158**	**412,802**

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 deduction for diluent costs is helpful to understand the Company's sales performance based on the net realized proceeds from the production net of diluent, the cost of which is partially recovered when the blended product is sold. Net sales do 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 9.

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 reconciliation in 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 (including oil and gas sales and other revenue, realized gains and losses from risk management contracts less royalties and diluent costs) 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	
	2019	**2018**	**2019**	**2018**
Net sales ($M)	340,431	228,389	1,261,517	1,083,492
Sales volumes (D&P) - (boe)	6,054,428	4,627,448	22,469,765	21,137,880
Net sales realized price ($/boe)	56.22	49.35	56.15	51.26

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	
	2019	**2018**	**2019**	**2018**
Production costs ($M)	89,789	84,441	310,084	324,400
Production (boe)	6,523,260	6,617,000	25,869,375	25,926,773
Production costs ($/boe)	13.76	12.76	11.99	12.51

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	
	2019	**2018**	**2019**	**2018**
Transportation costs ($M)	76,428	75,748	295,554	294,471
Net production (boe)	5,951,480	5,878,650	23,632,290	23,063,114
Transportation costs ($/boe)	12.84	12.89	12.51	12.77

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;
- Debt service requirements relating to existing and future debt; and
- Enhancing shareholder returns through dividends and share repurchases.

The Company funds 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, 2019, the Company had total cash balances of $455.8 million (including $127.4 million in restricted cash), which is $132.6 million lower than the prior year-end, primarily due to $131.3 million of excess cash provided from operating activities after capital expenditures and other investing activities. This was offset by $122.5 million in dividends paid to shareholders and the repurchase of shares under the NCIB, $73.6 million in lease and interest payments, and $56.3 million in payments to non-controlling interests including the acquisition of additional interest of Bicentenario.

Restricted cash includes amounts that have been set aside and are not available for immediate disbursement. The main components of restricted cash are long-term abandonment funds as required by the ANH and cash collateral required in certain legal processes. Abandonment funds will satisfy abandonment obligations and are expected to be released in the long-term as assets are abandoned. Abandonment funding requirements are updated annually, typically during the second quarter, and can be satisfied through additional allocations of restricted cash, designation of letters of credit, or a combination of both. Cash collateral for legal processes are expected to be released as the related processes are closed. As at December 31, 2019, total restricted cash of $127.4 million, decreased by $14.9 million from the prior year-end primarily due to new credit lines that allowed the Company to issue standby letters of credit releasing amounts that were restricted as a guarantee for abandonment obligations.

As at December 31, 2019, the Company had a working capital surplus of $71.4 million, a decrease of $144.3 million as compared to $215.7 million at the prior year-end, primarily due to dividends, share buybacks and higher current lease liabilities resulting from the adoption IFRS 16. The Company believes that working capital balances in conjunction with future cash flows from operations and available credit facilities are sufficient to support 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 unsecured notes issued on June 25, 2018 (the "**Unsecured Notes**"). 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 on June 25, 2023, unless earlier redeemed or repurchased.

Letter of Credit Facility

On May 17, 2018, the Company entered into a $100.0 million unsecured letter of credit facility with a maturity date of May 17, 2020 (the "**Unsecured LC Facility**"). The Unsecured LC Facility accrues interest at 3.0% per annum on any undrawn letters of credit, while amounts drawn under the facility accrue interest at 6% per annum. In November 2018, the Unsecured LC Facility was reduced to $60.0 million. As of December 31, 2019, the Company had $43.7 million in issued and outstanding letters of credit under the Unsecured LC Facility for exploratory, transportation and operational commitments. The Company expects to extend or replace the Unsecured LC Facility prior to its maturity date.

Guarantees

The Company has various guarantees in place in the normal course of business. As at December 31, 2019, in addition to letters of credit issued from the Unsecured LC Facility, the Company has $31.8 million of outstanding letters of credit to guarantee exploration and abandonment commitments. The lenders under these additional credit lines receive a fee equal to 3.0% per annum.

Covenants

The Unsecured Notes are senior, unsecured and rank equal in right of payment with all 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 (excluding its unrestricted subsidiaries), 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 these 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 Unsecured Notes also contain covenants that limit the Company's ability to, among other things, make certain investments or restricted payments, including dividends and share buybacks. As at December 31, 2019, the Company is in compliance with all such covenants.

1. Consolidated Debt to Consolidated Adjusted EBITDA Ratio is defined in the indenture governing the Unsecured Notes (the "**Indenture**") 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 Contractual Obligations

The Company's commitments and contractual obligations as at December 31, 2019, undiscounted and by calendar year, are presented below:

As at December 31, 2019 ($M)	2020	2021	2022	2023	2024	2025 and Beyond	Total
Financial obligations							
Long-term debt, including interest payments	33,950	33,950	33,950	366,975	—	—	468,825
Lease liabilities	34,178	31,114	8,831	7,819	—	—	81,942
Total financial obligations	**68,128**	**65,064**	**42,781**	**374,794**	**—**	**—**	**550,767**
Transportation and storage commitments							
Ocensa P-135 ship-or-pay agreement	80,825	68,367	68,367	68,367	68,367	34,360	388,653
Puerto Bahia take-or-pay agreement (1)	25,862	26,376	—	—	—	—	52,238
ODL ship-or-pay agreement	28,982	1,143	—	—	—	—	30,125
Bicentenario take-or-pay storage agreements (2)	7,663	7,663	7,663	7,663	5,887	—	36,539
Other transportation agreements (3)	36,432	30,358	30,283	29,444	29,444	103,985	259,946
Exploration commitments							
Minimum work commitments	148,301	127,564	50,202	12,950	—	—	339,017
Other commitments							
Operating purchases, leases and community obligations (4)	11,809	8,323	7,548	8,400	5,801	10,174	52,055
Total commitments	**339,874**	**269,794**	**164,063**	**126,824**	**109,499**	**148,519**	**1,158,573**

1. Excludes the lease component for ROU assets, which were recognized as lease liabilities upon the adoption of IFRS 16.
2. The Company has claimed against Bicentenario the termination of certain connected contracts for use of ancillary facilities related to the BIC Pipeline but was continuing to make payments pursuant to the contract as at December 31, 2019.
3. Includes take-or-pay commitments with CENIT related to the CLC and BIC Pipelines for $237.7 million for offloading, maritime facilities, and the Monterrey-Araguaney Pipeline. The Company has claimed against CENIT the termination of these contracts for the use of ancillary facilities but was continuing to make payments pursuant to the contracts as at December 31, 2019.
4. Excludes lease liabilities recognized on the Consolidated Statement of Financial Position upon the adoption of IFRS 16. Operating purchases and leases represent contractual commitments for service contracts and other short-term and low-value leases.

Other Guarantees and Pledges

The Company has granted a security interest in favour of Talisman Colombia Oil & Gas Ltd. ("**TCOG**") for variable and fixed payments up to a maximum of $48.0 million calculated on the basis of production from the CPE-6 block in Colombia. This relates to the Company's acquisition of TCOG's 50% working interest in the CPE-6 block. As of December 31, 2019, the Company has paid $2.1 million of such amounts under the agreement.

Contingencies

The Company is involved in various claims and litigation arising in the normal course of business. Since the outcomes of these matters are uncertain, there can be no assurance that such matters will be resolved in the Company's favour. The outcome of adverse decisions in any pending or threatened proceedings related to these and other matters could have a material impact on the Company's financial position, results of operations or cash flows.

Termination of Transportation Agreements

On July 12, 2018, the Company exercised contractual rights to terminate (a) three transportation contracts (the "**BIC Transportation Agreements**") with Bicentenario to ship oil through the BIC Pipeline which operates between Araguaney and Banadia where it connects to the CLC Pipeline because service had not been provided for more than six consecutive months, and (b) three related transportation agreements (the "**CLC Transportation Agreements**") with CENIT to ship oil through the CLC Pipeline because service had not been provided for more than 180 consecutive calendar days. The Company has received notice that CENIT and Bicentenario dispute the validity of those contract terminations, and that on December 3, 2018, CENIT, and on January 28, 2019, Bicentenario, commenced separate arbitration proceedings against the Company before the Centre for Arbitration and Conciliation of the Bogota Chamber of Commerce (the "**Bogota Arbitration Centre**") concerning the contract terminations. The arbitration claims have not been served on the Company, but the Company has been informed that in both proceedings it is claimed that the contract terminations were invalid, and that the Company remains liable to perform the applicable transportation agreements. The Company has been further informed that the primary relief requested in each proceeding is that the Company be ordered to pay with interest the monthly service payments that have not been paid since the contract terminations, and be ordered to pay future monthly service payments as they fall due. The CENIT claim also contains a dispute about whether the applicable tariff rate is a regulated tariff rate or a different tariff rate provided for by the CLC Transportation Agreements. Alternative, additional and amended relief has or may in the future also be claimed in both arbitration proceedings. As of December 31, 2019, the amount of tariffs claimed by CENIT under the CLC Transportation Agreement would be $83.0 million plus interest, and after December 31, 2019 would be approximately $70.3 million per annum, subject to tariff adjustments from time to time, until 2028. As of December 31, 2019, the aggregate amount of monthly service payments claimed by Bicentenario under the BIC Transportation Agreements would be $77.7 million (net of credits note and SBLCs) plus interest, and after December 31, 2019 would be approximately $130.6 million per annum, subject to tariff adjustments from time to time, until 2024.

The Company believes it was fully entitled to terminate both the BIC Transportation Agreements and the CLC Transportation Agreements and intends to vigorously defend the arbitration proceedings commenced by Bicentenario and CENIT and recover damages. On December 3, 2019, the Company and certain of its affiliates commenced arbitration proceedings before the Bogota Arbitration Centre seeking relief from Bicentenario and CENIT on the basis, amongst other things, that those contracts were validly terminated. The relief claimed against Bicentenario included payment of $486.5 million plus interest for letters of credit improperly drawn, service prepayments, credits and declared and unpaid dividends declared in 2018, and the relief claimed from CENIT included release of $32.6 million of restricted cash in connection with the dispute concerning the tariff rate for the CLC Pipeline applicable to service payments made before the termination of the CLC Transportation Agreements on July 12, 2018. The relief claimed against Bientenario and CENIT also includes termination of certain connected contracts for use of ancillary facilities related to the BIC Pipeline and the CLC Pipeline.

The Company has received notice that on December 3, 2019, Bicentenario commenced arbitration proceedings before the Bogota Arbitration Centre against various shareholders of Bicentenario including the Company, claiming that as a result of the loss of revenue resulting from the cessation of payments pursuant to various transportation contracts including the BIC Transportation Agreements, the shareholders are obliged to contribute additional funds to Bicentenario to cover debt service payments and other amounts. The Company believes that there is no basis for these proceedings.

Ecopetrol - Rubiales Field Disagreement

The Company has been involved in negotiations with Ecopetrol with respect to disagreements on wind-down costs and expenses, as well as inventory, in connection with the expiration of the Rubiales and Piriri exploration and production contracts in June 2016. On November 22, 2018, the Company filed a lawsuit against Ecopetrol before the Administrative Tribunal of Cundinamarca claiming it is owed $25.3 million. The Company is aware that Ecopetrol has claimed approximately $45 million. At this time, the Company has not yet been served such claim and therefore the Company cannot anticipate what the outcome of this proceeding will be or whether the final settled net amount will be significant.

Reversal of Provision Related to High-Price Clause

The Company has certain exploration and production contracts acquired through business combinations where outstanding disagreements with the ANH existed relating to the interpretation of PAP clauses. These contracts require high-price participation payments be made to the ANH for each designated exploitation area within a block under contract, which has cumulatively produced five million or more barrels of oil. The disagreement involves whether the cumulative production amounts in an exploitation area should be calculated individually (as each exploitation area represents independent reservoirs) or combined with other exploration areas within the same block for the purpose of determining the five million barrel threshold. The ANH has interpreted that the PAP should be calculated on a combined basis as opposed to the Company's interpretation that the calculation should be provided on an individual basis. Upon acquisition of these contracts and in accordance with IFRS 3 *Business Combinations*, provisions for contingent liabilities were recognized regarding these disagreements with the ANH.

For the year ended December 31, 2017, the Company reversed $99.6 million in provisions related to the Corcel Block after an arbitration panel ruling in favour of the Company's position, received on December 6, 2017. Subsequently, the ANH filed requests for annulment of the arbitration panel's decision with Colombia's highest administrative court. This request was rejected on November 21, 2018 and January 18, 2019. As a result, the arbitrators ruling in favour of the Company was upheld.

For the year ended December 31, 2018, the Company commenced a process to review other contingent liability provisions and reversed an additional $62.9 million for two blocks. The reversal was supported by external legal and technical opinions supporting the Company's interpretation that the PAP clause would not apply to a certain designated exploitation area within these blocks.

The Company and the ANH continue to review differences in interpretations for the remaining exploitation areas. The Company does not disclose the recorded provision amounts, as required by IAS 37 *Provisions, Contingent Liabilities and Contingent Assets*, on the grounds that this would be prejudicial to the outcome of potential future disputes with the ANH.

Tax Review in Colombia

The Colombian tax authority has assessed the Company with respect to certain income tax deductions relating to exploration expenditures, transportation costs, VAT credits and other expenses. As at December 31, 2019, the tax authority is assessing $224.2 million of tax owing, including interest and penalties (2018: $156.2 million). The Company has made a tax provision for $22.5 million relating to certain Colombian tax assessments, however, the Company believes that the remaining assessments will be resolved in its favour and, accordingly, no further income tax provision has been made regarding as at December 31, 2019.

Tax Review in Peru

The Peruvian tax authority has assessed the Company with respect to certain income tax deductions relating to exploration expenditures, VAT credits and other expenses. As at December 31, 2019, the tax authority is assessing $15.7 million of tax owing, including interest and penalties (2018: $21.5 million). The Company believes that the Peruvian tax assessments will be resolved in its favour and, accordingly, no income tax provision has been made as at December 31, 2019.

7. OUTSTANDING SHARE DATA

The Company has the following outstanding share data as at March 3, 2020:

	Number
Common shares	95,515,511
Deferred share units ("**DSUs**") (1)	283,518
Restricted share units ("**RSUs**") (2)	1,810,536

1. 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 a DSU 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 are determined by 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.
2. 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 and the achievement of corporate objectives. The value of a RSU increases or decreases as the price of the Common Shares increases or decreases, thereby promoting alignment of interests of an RSU holder with shareholders. RSU settlements are determined by 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.

Dividends

The Company has a policy to pay a regular quarterly dividend of approximately $15 million during quarters in which Brent oil price averages $60/bbl or higher. The declaration and payment of any specific dividend, including the actual amount, declaration date and record date will be subject to the discretion of the Board of Directors. The Company's dividends paid or declared during the years ended December 31, 2019 and 2018, are presented below:

Declaration Date	Record Date	Payment Date	Dividend (C$/ Share)	Dividends Amount ($M)	Number of DRIP Shares [1]
December 6, 2018	January 3, 2019	January 17, 2019	0.330	24,464	625,923
March 13, 2019	April 2, 2019	April 16, 2019	0.165	12,144	2,393
May 30, 2019	July 3, 2019	July 17, 2019	0.205	15,351	244
August 1, 2019	August 9, 2019	August 23, 2019	0.535	39,371	1,887
August 1, 2019	October 2, 2019	October 16, 2019	0.205	15,106	497
November 7, 2019	January 3, 2020	January 17, 2020	0.205	15,125	474,568
Total			1.645	121,561	1,105,512

1. In connection with the adoption of the dividend policy, the Company adopted a Dividends Reinvestment Program ("**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.

On March 4, 2020, the Company declared a regular dividend of C$0.205/share, which will be paid on or about April 16, 2020, to shareholders of record at the close of business on April 2, 2020.

Normal Course Issuer Bid

On October 16, 2019, the TSX approved the Company's notice to renew its NCIB, which had expired on July 17, 2019. Pursuant to the renewed NCIB, the Company can purchase for cancellation up to 6,532,400 of its Common Shares during the twelve-month period commencing October 18, 2019 and ending October 17, 2020. As at December 31, 2019, the Company had repurchased 1,548,814 Common Shares under its renewed NCIB.

The following table provides a summary of total share repurchases under the Company's NCIB programs:

	As at December 31	
	2019	**2018**
Number of common shares repurchased	2,642,834	1,590,585
Total amount of common shares repurchased	$ 21,752	$ 17,842
Weighted-average price per share	$ 8.23	$ 11.22

8. RELATED-PARTY TRANSACTIONS

The following tables provide the transaction amounts, total balances outstanding and commitments with related parties, as at December 31, 2019 and December 31, 2018, and for the years ended December 31, 2019 and 2018, respectively:

($M)		Accounts Receivable	Accounts Payable and Lease Obligation	Commitments [1]	Cash Advance [2] [3]	Long-term Receivable [2] [3]	Interest Receivable [2] [3]
ODL	2019	—	4,181	30,125	—	—	—
	2018	9,116	1,481	82,073	—	—	—
Bicentenario	2019	9,677	—	36,539	87,278	45,732	—
	2018	8,065	—	43,200	87,278	12,112	—
IVI	2019	—	31,193	52,238	17,741	151,452	52,267
	2018	—	1,104	123,330	17,741	123,036	37,158
CGX [4]	2018	—	—	—	—	25,945	2,186

1. Refer to the "Commitments and Contractual Obligations" section on page 21.
2. Items included as other assets in Consolidated Statement of Financial Position.
3. Amounts presented based on contractual payment obligations undiscounted and prior to impairments.
4. Balances shown reflect amounts before the Company acquired control of CGX on March 13, 2019. As a result, CGX is no longer a reportable related party.

($M)		Three months ended December 31 Sales	Purchases / Services	Interest Income (1)	Year ended December 31 Sales	Purchases / Services	Interest Income (1)
ODL	2019	—	11,306	—	—	49,356	—
	2018	—	12,354	—	1,359	46,472	—
Bicentenario	2019	—	1,441	—	—	6,557	—
	2018	—	1,306	—	—	59,448	—
IVI	2019	—	8,279	4,131	—	32,347	15,109
	2018	20	8,410	3,158	23	29,162	10,828
CGX (2)	2019	—	—	—	—	—	363
	2018	1	—	336	459	—	1,026
Interamerican (3)	2018	—	—	(166)	—	—	83

1. Amounts presented based on contractual payment obligations undiscounted and prior to impairments.
2. Balances shown reflect transactions before the Company acquired control of CGX on March 13, 2019.
3.Interamerican was sold in the fourth quarter of 2018 and was no longer related party as at December 31, 2018.

9. RISKS AND UNCERTAINTIES

The Company is exposed to a variety of known and unknown risks in the pursuit of its strategic objectives. The impact of any risk may adversely affect, among other things, the Company's business, reputation, financial condition, results of operations and cash flows, which may affect the market price of its securities.

The Company has an enterprise risk management program that plans, identifies, evaluates, prioritizes and monitors risk across the organization and supports decision-making. This program identifies critical strategic risk to its people, the environment, its assets, regulatory environment and reputation, and systematically mitigates these risks to an acceptable level. In addition, we continuously monitor our risk profile as well as industry best practices.

The Company attempts to mitigate its financial, operational and strategic risks to an acceptable level through a variety of policies, systems and processes. The following provides a list of the most significant risks relating to the Company and its operations.

Significant Risk Factors

Reserves

As a participant in the oil and natural gas industry, Frontera is exposed to operational risks such as: the inability to find new blocks or reserves that are commercially and economically feasible, unsuccessful exploration and exploitation activities, premature declines of reservoirs and uneconomic transportation methods. The Company believes it has set up appropriate mitigation measures to protect against these risks. Some of these measures include diversifying the Company's asset base, developing reserve development strategies, employing highly skilled employees and utilizing available technology.

Liquidity/Financial

The Company is exposed to normal financial risks inherent in the oil and natural gas industry, including liquidity risk, commodity price risk, exchange rate risk, interest rate risk and credit risk. For further information on liquidity and capital risk mitigation see section "Liquidity and Capital Resources" section on page 20.

The Company also continuously monitors opportunities to use financial instruments such as derivatives to manage exposure to fluctuations in commodity prices and foreign currency rates. For further information see the sections "Risk Management Contracts - Brent Crude Oil" section on page 13 and "Risk Management Contracts - Foreign Exchange" section on page 14.

The use of such financial instruments expose the Company to risks of financial loss. These risks arise from, but are not limited to, the change in the price of the underlying asset, poor correlation between the valuation of the financial instrument and the valuation of the underlying asset being hedged, unenforceability of contracts and counterparty default.

Health, Safety and Environmental

Given the operational and technical complexity associated with the oil and gas industry, the Company is subject to health, safety and the environment risk. The Company seeks to minimize these risks by measuring and monitoring HSE standards on a continuous basis and conducting its operations in a safe and reliable manner in accordance with high safety standards. Failure to manage the risks effectively could result in potential fatalities, serious injury, interruptions to operations, damage to assets, environmental impact or loss of license to operate. Emergency preparedness, business continuity and security policies and programs are in place for all operating areas and are adhered to on an ongoing basis. The Company, in accordance with industry practice, maintains insurance coverage against losses from certain of these risks. Nonetheless, insurance proceeds may not be sufficient to cover all losses, and insurance coverage may not be available for all types of operational risks.

Security Information

The Company is subject to a variety of information technology and system risks as a part of its normal course operations, including cyber-attacks, information fraud or theft, compromise of the confidentiality and integrity of corporate information, critical infrastructure, personal data and normal operations.

Although the Company has security measures, processes and controls in place that are designed to mitigate these risks, a breach of its security measures and/or a loss of information could occur and result in a loss of material and confidential information and reputation, breach of privacy laws and disruption to its business activities. The significance of any such event is difficult to quantify but may in certain circumstances be material and could have a material adverse effect on the Company's business, financial condition and results of operations.

Political Risks

The Company has assets and investments across South America. As such, the Company is subject to political risks such as changes in laws and regulations, lack of governance in areas where we operate, change in political regimes and regulatory instability. If these risks materialize, it could impact our operations, delay existing projects and/or cause higher operating costs. In order to manage these risks, the Company engages with local governments and stakeholders, has established plans for monitoring and reacting to legislative changes and continues to develop a balanced and diversified portfolio of assets in the areas where we operate.

The list above does not contain all the risks associated with an investment in the securities of the Company. For a more comprehensive discussion of the risks and uncertainties that could have an effect on the business and operations of the Company, please see the Company's AIF and Consolidated Financial Statements 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 3a 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. Effective January 1, 2019, the Company adopted IFRS 16 - Leases on a modified retrospective basis with no changes to comparative period amounts. As a result of adopting IFRS 16, the Company recognized a significant increase to both non-current assets and lease liabilities. The full effect on adoption of this new accounting standard is further described in Note 3b of the Consolidated Financial Statements.

In addition, the Company voluntarily changed its accounting policy to classify interest paid as a financing activity, instead of an operating activity as previously reported in the Consolidated Statement of Cash Flows. The Company considers the classification of these interest payments within financing activities to be more useful to financial statement users and, consequently, would provide more relevant and reliable information. Further information is included in Note 3b of the Consolidated Financial Statements.

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 3c 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, 2019. 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, 2019.

There have been no changes in the Company's ICFR during the quarter ended December 31, 2019, 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, 2019.

12. FURTHER DISCLOSURES

Production Reporting

Production volumes are reported on a Company working interest before royalties basis, including 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 following table includes the average net production:

	Net Production (in boe/d)				
				Year ended December 31	
Producing blocks in Colombia	**Q4 2019**	**Q3 2019**	**Q4 2018**	**2019**	**2018**
Heavy oil	29,778	30,758	24,963	29,321	24,347
Light and medium oil	24,155	25,726	28,022	26,896	27,668
Natural gas	2,224	2,283	3,263	2,401	4,186
Net production Colombia	**56,157**	**58,767**	**56,248**	**58,618**	**56,201**
Producing blocks in Peru					
Light and medium oil	8,533	5,504	7,650	6,128	6,986
Net production Peru	**8,533**	**5,504**	**7,650**	**6,128**	**6,986**
Total net production	**64,690**	**64,271**	**63,898**	**64,746**	**63,187**

Overlift and Settlement

Overlift and 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 or operating EBITDA impact during the quarter. When the overlift is settled, this expense is reversed to recognize the gross margin and operating EBITDA earned on the related sale in the period of production. Refer to the "Oil and Gas Operating Costs" section on page 10.

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