MANAGEMENT DISCUSSION & ANALYSIS

May 4, 2021

For the three months ended March 31, 2021

*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 Interim Condensed Consolidated Financial Statements and related notes for the three months ended March 31, 2021 and 2020 ("**Interim Financial Statements**"). Additional information with respect to the Company, including the Company's quarterly and annual financial statements and Company's Annual Information Form for the year ended December 31, 2020, dated March 3, 2021 (**"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.*

*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 14.*

Certain statements in this MD&A constitute forward-looking statements or "forward-looking information (collectively, "forward-looking statements") within the meaning of applicable securities legislation, which involve known and unknown risks, uncertainties, and other factors that may cause the actual results, performance or achievements of the Company or industry results to be materially different from any future results, performance or achievements expressed or implied by such 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 the impact of a sustained low oil price environment due to the ongoing impacts of the COVID-19 pandemic, and actions of the Organization of Petroleum Exporting Countries and non-OPEC countries, the expected impact of measures that the Company has taken and continues to take in response to these events, expectations regarding the Company's ability to manage its liquidity and capital structure and generate sufficient cash to support operations, capital expenditures and financial commitments, the timing of release of restricted cash, the impact of fluctuations in the price of, and supply and demand for oil and natural gas products, production levels, cash levels, reserves, capital expenditures (including plans and projects related to drilling, exploration activities, and infrastructure and the timing thereof), operating EBITDA, production costs, transportation costs and the impact of the Conciliation Agreement 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 currently believes the expectations reflected in these forward-looking statements are reasonable, but 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 headings "Forward-Looking Information" and "Risk Factors" in the Company's AIF and under the heading "Risks and Uncertainties" in this MD&A. 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.

*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.*

1. PERFORMANCE HIGHLIGHTS

Financial and Operational Summary

		Q1 2021	Q4 2020	Q1 2020
Operational Results				
Heavy crude oil production	(bbl/d)	20,997	21,074	31,996
Light and medium crude oil production	(bbl/d)	18,685	19,756	29,539
Total crude oil production [(1)]	(bbl/d)	39,682	40,830	61,535
Conventional natural gas production [(1)]	(mcf/d)	5,227	6,356	11,611
Total production [(2)(3)]	(boe/d) [(4)]	40,599	41,945	63,572
Oil & gas sales, net of purchases [(5)]	($/boe)	58.18	42.20	41.57
Realized (loss) gain on risk management contracts	($/boe)	(3.53)	(2.00)	2.65
Royalties	($/boe)	(1.96)	(0.47)	(1.18)
Diluent costs	($/boe)	(2.13)	(1.75)	(1.28)
Net sales realized price [(6)]	($/boe)	50.56	37.98	41.76
Production costs [(7)]	($/boe)	(10.54)	(13.46)	(12.48)
Transportation costs [(8)]	($/boe)	(10.89)	(10.93)	(12.44)
Operating netback [(9)]	($/boe)	29.13	13.59	16.84
Financial Results				
Oil & gas sales, net of purchases	($M)	180,956	172,980	242,835
Realized (loss) gain on risk management contracts	($M)	(10,980)	(8,205)	15,490
Royalties	($M)	(6,110)	(1,925)	(6,900)
Diluent costs	($M)	(6,614)	(7,158)	(7,468)
Net sales [(9)]	($M)	157,252	155,692	243,957
Net (loss) income [(10)]	($M)	(14,126)	48,636	(387,809)
Per share – basic	($)	(0.14)	0.50	(4.04)
Per share – diluted	($)	(0.14)	0.48	(4.04)
General and administrative	($M)	13,202	19,851	15,015
Operating EBITDA [(9)]	($M)	69,158	35,639	46,982
Cash provided by operating activities	($M)	47,393	42,055	46,541
Capital expenditures [(11)]	($M)	14,365	24,871	64,676
Cash and cash equivalents – unrestricted	($M)	248,237	232,288	265,009
Restricted cash short and long-term	($M)	161,230	168,934	96,260
Total cash	($M)	409,467	401,222	361,269
Total debt and lease liabilities	($M)	534,656	538,244	390,259
Consolidated total indebtedness (excluding Unrestricted Subsidiaries) [(12)]	($M)	361,699	362,001	349,778
Net debt (excluding Unrestricted Subsidiaries) [(12)]	($M)	139,327	146,976	98,269

1. Reference to crude oil or natural gas production in the above table and elsewhere in this MD&A refer to the light and medium crude oil and heavy crude oil and conventional natural gas, respectively, product types as defined in National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities.
2. Represents working interest production before royalties and total volumes produced from service contracts. Refer to the "Further Disclosures" section on page 22.
3. Natural gas liquids have not been presented separately because production for such product type was immaterial to the Company.
4. Boe has been expressed using the 5.7 to 1 Colombian Mcf/bbl conversion standard required by the Colombian Ministry of Mines & Energy.
5. "Oil & gas sales, net of purchases" is a non-IFRS measure and includes crude oil and natural gas sales, net of the cost of volumes purchased from third-party. For further detail refer to the "Non-IFRS Measures" section on page 14.
6. Per boe is calculated using sales volumes from development and producing ("D&P") assets. Volumes purchased from third parties are excluded.
7. Per boe is calculated using production.
8. Per boe is calculated using net production after royalties.
9. Refer to the "Non-IFRS Measures" section on page 14. This section also includes a description and details for all per boe metrics included in operating netback.
10. Net (loss) income attributable to equity holders of the Company.
11. Capital expenditures includes costs, net of income from exploration and evaluation ("**E&E**") assets.
12. Refer to the "Non-IFRS Measures" section on page 14. ("**Unrestricted Subsidiaries**") include CGX Energy Inc.("**CGX**"), ODL JV Ltd. ("**ODL JV**"), and Frontera Bahía Holding Ltd., including its subsidiary Sociedad Portuaria Puerto Bahía S.A.("**Puerto Bahia**").

Performance Highlights

First Quarter 2021

During first quarter of 2021, the Company continued to deliver strong performance results as it benefited from the stronger oil prices and the substantive changes made to the business during 2020 to streamline operations and implement efficiencies. These initiatives have resulted in higher cash flows from operating activities and operating EBITDA generated on a lower cost base for production, transportation and general & administrative activities compared to the same prior year quarter. These actions helped the Company's liquidity position, ending with a total cash position of $409.5 million, including $161.2 million of restricted cash.

The Company also began to ramp up its development activity during the quarter with the drilling of one development well and mobilization of four drill rigs in Colombia, as well as advancing its exploration activity in offshore Guyana with preparations underway to drill the Kawa-1 well in the Corentyne block during the third quarter of 2021. In Ecuador, seismic acquisition planning and other preliminary activities are underway in advance of drilling in the Espejo and Perico blocks in the second half of 2021 or early 2022.

Finally, the Company advanced on shareholder return initiatives, receiving TSX approval to purchase up to 5,197,612 Common Shares over a twelve-month period commencing on March 17, 2021, under a normal course issuer bid ("**NCIB**"). A total of 768,800 Common Shares for a total of $4.0 million were purchased for cancellation as of May 3, 2021.

Financial and Operational Results

- Production averaged 40,599 boe/d (consisting of 18,685 bbl/d of light crude oil and medium crude oil, 20,997 bbl/d of heavy crude oil and 5,227 Mcf/d of conventional natural gas), compared with 41,945 boe/d (consisting of 19,756 bbl/d of light crude oil and medium crude oil, 21,074 bbl/d of heavy crude oil and 6,356 Mcf/d of conventional natural gas) in the prior quarter and 63,572 boe/d (consisting of 29,539 bbl/d of light crude oil and medium crude oil, 31,996 bbl/d of heavy crude oil and 11,611 Mcf/d of conventional natural gas) in the first quarter of 2020.
- Cash provided by operating activities was $47.4 million, compared with $42.1 million in the prior quarter and $46.5 million in the first quarter of 2020. The Company reported a total cash position of $409.5 million at March 31, 2021, including $161.2 million of restricted cash. $361.3 million at March 31, 2020, including $96.3 million of restricted cash.
- Net loss was $14.1 million ($0.14/share), compared with net income of $48.6 million ($0.50/share) in the prior quarter and net loss of $387.8 million ($4.04/share) in the first quarter of 2020.
- Capital expenditures were $14.4 million, compared with $24.9 million in the prior quarter and $64.7 million in the first quarter of 2020.
- Operating EBITDA was $69.2 million, compared with $35.6 million in the prior quarter and $47.0 million in the first quarter of 2020.
- Operating netback was $29.13/boe, compared with $13.59/boe in the prior quarter and $16.84/boe in the first quarter of 2020.

2. GUIDANCE

The following table reports the Company´s full year 2021 guidance metrics as released on March 3, 2021. There are no changes to the Company's guidance, which was prepared using a Brent oil price assumption of $60/bbl and COP/USD exchange rate of 3500:1.

		2021 FY Guidance
Average production	(boe/d)	40,500 to 42,500
Production costs	($/boe)	10.0 to 11.0
Transportation costs	($/boe)	10.5 to 11.5
Operating EBITDA	($MM)	275 to 325
Development capital	($MM)	110 to 130
Exploration capital	($MM)	70 to 130
Infrastructure and other capital	($MM)	20 to 35
Capital expenditures [(1)]	($MM)	200 to 295

1. Capital expenditures guidance does not include decommissioning costs. The Company expects to execute $10 million of decommissioning in 2021, including $4 million in Peru.

3. FINANCIAL AND OPERATIONAL RESULTS

Production

The following table summarizes the average production before royalties from the Company's operations in Colombia and Peru. Refer to the "Further Disclosures" section on page 22 for details of the Company's net production.

		Production		
Producing blocks in Colombia		**Q1 2021**	**Q4 2020**	**Q1 2020**
Heavy oil	(bbl/d)	20,997	21,074	31,996
Light and medium oil	(bbl/d)	18,685	19,756	24,154
Conventional natural gas production	(mcf/d)	5,227	6,356	11,611
Total production Colombia	**(boe/d)**	**40,599**	**41,945**	**58,187**
Producing blocks in Peru				
Light and medium oil	(bbl/d)	—	—	5,385
Total production Peru	**(bbl/d)**	**—**	**—**	**5,385**
Total production	**(boe/d)**	**40,599**	**41,945**	**63,572**

Colombia

Production in Colombia for the three months ended March 31, 2021, decreased by 3% compared to the prior quarter. Production decreased in light and medium oil and natural gas as a result of natural decline in some of the Company´s mature fields. Heavy oil production was relatively flat compared to the prior quarter as reductions of water disposal volumes at Quifa were partially offset by an increase in production at CPE-6 from a new well drilled on the block. At the end of the first quarter, the Company voluntarily and temporarily reduced production at Quifa as it seeks to identify additional water disposal options in the block. The Company anticipates production returning to prior planned levels in the third quarter of 2021.

Compared to the first quarter of 2020, production decreased by 30% as a result of natural decline due to the significant curtailments in drilling activities starting in the second quarter of 2020. This drilling suspension was part of the Company's program to manage the impact of the COVID-19 pandemic and the lower oil price environment during 2020.

Peru

The Company reported no production in Peru for the first quarter of 2021 and the fourth quarter of 2020, compared with 5,385 bbl/d in the first quarter of 2020. The service contract for Block 192 was suspended in February 2020 with no operations until its expiry on February 5, 2021. The Company continues to sell oil inventory and complete remediation work as it no longer has production contracts in Peru.

Production Reconciled to Sales Volumes

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

		Q1 2021	Q4 2020	Q1 2020
Production	**(boe/d)**	**40,599**	**41,945**	**63,572**
Royalties in-kind Colombia	(boe/d)	(2,762)	(2,818)	(4,351)
Royalties in-kind Peru (1)	(boe/d)	—	—	(890)
Net production	**(boe/d)**	**37,837**	**39,127**	**58,331**
Oil inventory (build) draw	(boe/d)	(751)	6,443	8,526
(Settlement) overlift	(boe/d)	(640)	609	—
Other inventory movements (2)	(boe/d)	(1,208)	(1,602)	(2,524)
Sales volumes	**(boe/d)**	**35,238**	**44,577**	**64,333**
Sale of volumes purchased	(boe/d)	(683)	(26)	(147)
Sales volumes, net of purchases	**(boe/d)**	**34,555**	**44,551**	**64,186**
Oil sales volumes	(bbl/d)	33,648	43,490	62,215
Natural gas sales volumes	(mcf/d)	5,170	6,048	11,235
Total oil and natural gas sales volumes, net of purchases	**(boe/d)**	**34,555**	**44,551**	**64,186**
Inventory balance				
Colombia	(bbl)	602,536	119,792	666,378
Peru (3)	(bbl)	580,499	995,585	852,998
Inventory ending balance	**(bbl)**	**1,183,035**	**1,115,377**	**1,519,376**

1. The Company reported the share of production retained by the government of Peru as royalties paid in-kind.
2. Mainly corresponds to operational consumption and quality volumetric compensation.
3. The Company sold one cargo in Peru during the first quarter of 2021 and expects to sell the remaining oil inventory in Peru during 2021.

Sales volumes, net of purchases for the three months ended March 31, 2021, were lower than the prior quarter by 22%, due to the drawdown of oil inventory in the fourth quarter of 2020 and the settlement of an overlift balance from the previous quarter. In comparison to the first quarter of 2020, sales volumes decreased by 46% mainly due to lower production in Colombia and no production in Peru.

Colombia Royalties - PAP

The Company makes PAP payments to Ecopetrol S.A. and the Agencia Nacional de Hidrocarburos ("**ANH**") on production from the Quifa, Cubiro, Corcel, Guatiquia, Cravoviejo and Arrendajo blocks. The PAP is 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).

		Q1 2021	Q4 2020	Q1 2020
PAP in cash	(bbl/d)	201	70	764
PAP in kind	(bbl/d)	19	—	260
PAP	**(bbl/d)**	220	**70**	**1,024**
% Production		**0.5 %**	**0.2 %**	**1.6 %**

For the three months ended March 31, 2021, PAP decreased compared with the same period of 2020 primarily due to lower production despite the increase in WTI oil benchmark price. Compared to the previous quarter, PAP increased due to higher WTI oil benchmark price.

Realized and Reference Prices

		Q1 2021	Q4 2020	Q1 2020
Reference price				
Brent	($/bbl)	61.32	45.26	50.82
Average realized prices				
Realized oil price, net of purchases	($/bbl)	59.15	42.66	42.20
Realized natural gas price	($/mcf)	3.96	4.16	3.84
Net sales realized price				
Oil & gas sales, net of purchases	($/boe)	58.18	42.20	41.57
Realized (loss) gain on risk management contracts	($/boe)	(3.53)	(2.00)	2.65
Royalties	($/boe)	(1.96)	(0.47)	(1.18)
Diluent costs	($/boe)	(2.13)	(1.75)	(1.28)
Net sales realized price	**($/boe)**	**50.56**	**37.98**	**41.76**

The average Brent benchmark price during the three months ended March 31, 2021, increased by 21%, compared to the same period of 2020. The increase in crude oil prices was mostly attributable to a better global economic outlook, as a result of global government fiscal incentive programs and the increase in global industrial activity, specifically in Asia. Compared to the fourth quarter of 2020, the Brent benchmark price increased by 35% as a result of the rollouts of the COVID-19 vaccine and OPEC+ crude oil production cuts.

For the three months ended March 31, 2021, the Company's net sales realized price was $50.56/boe an increase of 33% and 21%, compared with the fourth quarter of 2020 and the same period of 2020, respectively, due to higher Brent benchmark prices as well as narrower sales price differential, partially offset by higher realized losses on risk management contract during the first quarter of 2021 compared to gain in the first quarter of 2020, higher royalties and higher diluent cost per barrel due to lower sales of volumes produced.

Operating Netback

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

	Q1 2021		Q4 2020		Q1 2020	
	$M	($/boe)	$M	($/boe)	$M	($/boe)
Net sales realized price [(1) (2)]	157,252	50.56	155,692	37.98	243,957	41.76
Production costs [(3)]	(38,513)	(10.54)	(51,930)	(13.46)	(72,210)	(12.48)
Transportation costs [(4)]	(37,084)	(10.89)	(39,354)	(10.93)	(66,052)	(12.44)
Operating Netback [(5)]	**81,655**	**29.13**	**64,408**	**13.59**	**105,695**	**16.84**
		(boe/d)		(boe/d)		(boe/d)
Sales volumes, net of purchases D&P - (boe) [(2) (6)]		34,555		44,551		64,186
Production [(7)]		40,599		41,945		63,572
Net production [(8)]		37,837		39,127		58,331

1. Per boe is calculated using produced sales volumes from D&P assets. Refer to the "Realized and Reference Prices" on page 5.
2. Prior period figures are different compared with those previously reported as a result of the change in the treatment of purchased volumes and cost of purchases according with the new operating netback approach. Refer to "Non-IFRS Measures" section on page 14 for further details.
3. Per boe is calculated using production.
4. Per boe is calculated using net production after royalties.
5. Refer to the "Non-IFRS Measures" section on page 14 for details and a description of the operating netback calculation.
6. Sales volumes, net of purchases D&P exclude volumes from E&E assets as the related sales and costs are capitalized under IFRS, and sales of third-party volumes.
7. Refer to the "Production" section on page 4.
8. Refer to the "Further Disclosures" section on page 22.

Operating netback for the first quarter of 2021 was $29.13/boe, compared to $16.84/boe in the same quarter of 2020. The increase was primarily due to higher net sales realized price, lower production costs resulting from the closure of Peru operations in Block 192, renegotiation of contract rates with suppliers, other operational optimizations and, reduction of transportation cost due to the cessation of payments for unused facilities under the BIC Ancillary Agreements and the CLC Ancillary Agreements since March 2020 (for further information refer to Note 28 of the Company's audited annual consolidated financial statements for the year ended December 31, 2020 (the "**2020 Annual Consolidated Financial Statements"**) and, accounting eliminations from the consolidation of Puerto Bahia since its acquisition in the third quarter of 2020.

In comparison to the fourth quarter of 2020, operating netback for the first quarter of 2021 increased from $13.59/boe to $29.13/boe, primarily due to higher net sales realized price and 22% reduction in production costs. The decrease in production costs on a per boe basis was primarily the result of a prior period provision for remediation costs in Peru ($1.43/boe), higher maintenance (mainly well services and internal road maintenance) executed during the fourth quarter and a weaker COP which positively impacts production costs.

Sales

	Three months ended March 31	
($M)	**2021**	**2020**
Oil & gas sales, net of purchases [(1)]	180,956	242,835
Realized (loss) gain on risk management contracts	(10,980)	15,490
Royalties	(6,110)	(6,900)
Diluent costs	(6,614)	(7,468)
Net sales	**157,252**	**243,957**
$/boe using sales volumes from D&P assets	50.56	41.76

1. "Oil & gas sales, net of purchases" is a non-IFRS measure and includes crude oil and natural gas sales, net of the cost of the third-party volumes purchased. For further detail refer to the "Non-IFRS Measures" section on page 14.

Oil & gas sales, net of purchases for the three months ended March 31, 2021, decreased by $61.9 million compared to the same period of 2020, mainly due to reduced sales volumes because of lower production (refer to the "Production" section on page 4 for further detail on changes in productions volumes), partially offset by higher Brent benchmark prices and narrower sales price differential (refer to the "Realized and Reference Prices" section on page 5 for the further detail on changes in prices).

Net sales for the three months ended March 31, 2021, decreased by $86.7 million compared with the same period of 2020. The following table describes the various factors that impacted net sales:

	Three months ended March 31
($M)	**2021-2020**
Net sales for the quarter ended March 31, 2020	243,957
Increase due to 40% higher oil and gas price	97,009
Decrease due to lower volumes sold of 29,631 boe/d or 46%	(158,888)
Change to realized loss on risk management contracts	(26,470)
Decrease in diluent costs	854
Decrease in royalties	790
Net sales for the period ended March 31, 2021	**157,252**

Oil and Gas Operating Costs

	Three months ended March 31	
($M)	**2021**	**2020**
Production costs	38,513	72,210
Transportation costs	37,084	66,052
Diluent costs	6,614	7,468
Cost of purchases (1)	4,004	1,003
Inventory valuation	3,228	43,115
(Settlement) overlift	(2,659)	150
Total oil and gas operating costs	**86,784**	**189,998**

1. Cost of third-party volumes purchased for use and resale in the Company's oil operations, including its transportation and refining activities.

For the three months ended March 31, 2021, total oil and gas operating costs decreased by 54% compared to the same period of 2020. The variance in total oil and gas operating costs was mainly due to the following:

- Production costs for the three months ended March 31, 2021, were 47% lower than the comparable period in 2020, primarily due to the closure of Peru operations and, reductions in variable cost in Colombia as a result of reduced production. In addition, as the Company took significant steps to optimize its production costs by renegotiating key contractor rates in response to the decline in oil prices during 2020, these actions resulted in the reduced cost of hired services, chemical treatment, and rental expenses.
- Transportation costs for the three months ended March 31, 2021, were 44% lower than the same period of 2020, primarily due to less barrels transported in Colombia as a result of lower production and the cessation of payments for unused facilities under the BIC Ancillary Agreements and the CLC Ancillary Agreements since March 2020, and accounting eliminations from the consolidation of Puerto Bahia since its acquisition in the third quarter of 2020.
- Diluent costs in the first quarter of 2021, were 11% lower than the same quarter of 2020, mainly due to lower dilution services resulting from the decrease in heavy oil production, and accounting eliminations from the consolidation of Puerto Bahia since its acquisition in the third quarter of 2020.
- Cost of purchases in the first quarter of 2021, were higher than the same quarter of 2020, due to the higher Brent price and volumes of 536 bbl/d acquired from third parties.
- Overlift (settlement) decreased due to the settlement of an overlift balance during the current period. The Company had no significant overlift positions during the first quarter of 2021.
- Inventory valuation expense for the first quarter of 2021, was $39.9 million lower compared with the same quarter of 2020 due to a significant drawdown of inventory in the previous year.

Costs Under Terminated Pipeline Contracts

For the first quarter of 2021, the Company had $Nil of costs under terminated pipeline contracts. As at March 31, 2020, the Company recorded $2.8 million of costs in relation to the BIC Ancillary Agreements and CLC Ancillary Agreements. For further information refer to Note 28 of the 2020 Annual Consolidated Financial Statements.

Royalties

($M)	Three months ended March 31 2021	2020
Royalties Colombia	6,110	6,857
Royalties Peru	—	43
Royalties	**6,110**	**6,900**
$/boe using sales volumes from D&P assets	1.96	1.18

Royalties include cash payments for PAP, royalties and amounts paid to previous owners of certain blocks in Colombia. For the three months ended March 31, 2021, royalties decreased by $0.8 million compared to the same period of 2020 primarily due to lower production. Refer to the "Production Reconciled to Sales Volumes" section on page 4 for further details of royalties paid in-cash and in-kind. On a per boe basis, royalties increased by $0.78 boe/d compared to the same period of 2020 primarily due to the 46% reduction of volumes sold.

Depletion, Depreciation and Amortization

($M)	Three months ended March 31 2021	2020
Depletion, depreciation and amortization	32,636	88,020

For the three months ended March 31, 2021, depletion, depreciation and amortization expense ("**DD&A**") decreased by 63% compared to the same period of 2020, mainly due to lower depletable base as a result of a reduction in abandonment cost estimates and lower capital expenditures, as well as a decrease in production and inventory build up during the first quarter of 2021.

Impairment, Exploration Expenses and Other

($M)	Three months ended March 31 2021	2020
Impairment of:		
Properties plant and equipment	—	77,864
Intangible assets	—	54,881
Exploration and evaluation assets	—	17,124
Other	—	888
Total impairment	**—**	**150,757**
Exploration expenses	82	433
Recovery of asset retirement obligations	(5,738)	(2,623)
Impairment, exploration expenses and other	**(5,656)**	**148,567**

For the three months ended March 31, 2021, the impairment was $Nil as no indicators were identified. In the first quarter of 2020, the Company recorded an impairment charge of $150.8 million primarily as a result of lower forecasted oil prices which reduced the expected future cash flows of its CGUs. As a result of the impairment test, the carrying amounts of certain assets relating to the Colombia CGUs were reduced to their recoverable amounts. The recoverable amount of each CGU was determined based on the Company's updated projections of future cash flows generated from proved and probable reserves. For further information refer to Note 6 of the Interim Condensed Consolidated Financial Statements for the three months ended March 31, 2020 and 2019. Subsequently, the Company partially reversed this impairment charge in the fourth quarter of 2020 primarily due to the increase in oil prices.

During the first quarter 2021, a recovery of $5.7 million relating to the asset retirement obligation of relinquished blocks was recognized, compared to $2.6 million in the same quarter of 2020 as a result of more blocks being relinquished during the first quarter of 2021.

Other Operating Costs

($M)	Three months ended March 31 2021	2020
General and administrative	13,202	15,015
Share-based compensation	1,317	1,217
Restructuring, severance and other costs	381	6,408

General and Administrative

For the three months ended March 31, 2021, G&A expenses decreased 12% compared with the same period of 2020, mainly due to costs efficiencies, reduced discretionary spending and lower personnel costs from organizational restructuring activities.

Share-based Compensation

For the three months ended March 31, 2021, share-based compensation was comparable with the same period of 2020. Share-based compensation reflects non-cash charges relating to the vesting of restricted share units and grants of deferred share units under the Company's incentive plan which are subject to variability from movements in its underlying share price, and the consolidation of stock option expenses from CGX.

Restructuring, Severance and Other Costs

For the three months ended March 31, 2021, restructuring, severance and other costs decreased by $6.0 million compared with same period of 2020, primarily due to higher severance charges during the first quarter 2020 as part of the Company's efforts to streamline operations in response to the lower oil price environment.

Non-Operating Costs

($M)	Three months ended March 31 2021	2020
Finance income	840	4,678
Finance expenses	(13,587)	(15,260)
Foreign exchange loss	(18,488)	(20,597)
Other loss, net	(9,601)	(2,991)

Finance Income

For the three months ended March 31, 2021, finance income decreased by $3.8 million mainly due to the accounting elimination of the interest income from the long-term receivable to Infrastructure Venture Inc. ("**IVI**") after its consolidation, and lower average cash balances.

Finance Expense

For the three months ended March 31, 2021, finance expense decreased by $1.7 million mainly due to the discount to present value of dividends declared by Oleoducto Bicentenario de Colombia S.A.S. ("**Bicentenario**") during the first quarter of 2020 and, lower lease interest due to the modification of lease assets, partially offset by the interest expense consolidated from the acquisition of IVI.

Foreign Exchange Loss

For the three months ended March 31, 2021, foreign exchange loss was $18.5 million, due to the translation of the debt consolidated from IVI during 2020 and the Company's net working capital balances denominated in COP, compared with a loss of $20.6 million in the same period of 2020, primarily due to the impact of the 24% depreciation of the COP against the USD on the translation of the Company's net working capital balances denominated in COP.

Other Loss, net

For the three months ended March 31, 2021, the Company recognized other losses of $9.6 million compared to $3.0 million in the same period of 2020. The increase during the first quarter of 2021 was primarily due to the recognition of legal claims relating to the reassessment of contingencies from the late delivery of production from the Quifa block prior to 2014 (for further information refer to Note 15 of the Interim Financial Statements).

(Loss) Gain on Risk Management Contracts

	Three months ended March 31	
($M)	2021	2020
Realized (loss) gain on risk management contracts[1]	(10,980)	15,490
Unrealized (loss) gain on risk management contracts[2]	(8,838)	29,140
Total (loss) gain on risk management contracts	**(19,818)**	**44,630**

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 ended March 31, 2021, the realized loss on risk management contracts was $11.0 million, compared to a $15.5 million gain in the same period of 2020, primarily from the cash settlement on 3-ways and Put Spreads contracts during the first quarter of 2021 at an average price of $61.17/bbl.

The unrealized loss on risk management contracts for the three months ended March 31, 2021, was $8.8 million compared to a $29.1 million gain in the same period of the previous year due to the increase in the benchmark forward prices of Brent oil.

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. The Company's strategy aims to protect a minimum of 40% of the estimated production with a tactical approach, using a combination of instruments, capped and non-capped, to protect the revenue generation and cash position of the Company, while maximizing the upside. This diversification of instruments allows the Company to take a more dynamic approach to the management of its hedging portfolio. In 2021, the Company executed a risk management strategy using a variety of derivatives instruments, including 3 - ways, puts and put spreads primarily to protect against downward oil price movements.

				Avg. Strike Prices	Carrying Amount ($M)	
Type of Instrument	**Term**	**Benchmark**	**Notional Amount / Volume (bbl)**	**Put / Call; Call Spreads $**	**Assets**	**Liabilities**
3-ways	April to December 2021	Brent	1,750,000	27.8/37.8/54.0	—	16,918
Put Spread	April to December 2021	Brent	2,994,000	27.3/47.3	3,262	—
Put	July to September 2021	Brent	713,000	$60.0	3,315	—
Total as at March 31, 2021					**6,577**	**16,918**

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 March 31, 2021, the Company has entered into new positions of foreign currency derivatives contracts, detailed as follows:

					Carrying Amount	
Type of Instrument	**Term**	**Benchmark**	**Notional Amount / Volume USD**	**Put/ Call; Par forward (COP$)**	**Assets**	**Liabilities**
Zero-cost collars	April to December 2021	COP / USD	$ 180,000	3,500 / 3,964	—	91
Total as at March 31, 2021					**—**	**91**

Risk Management Contracts - Interest Rate Swap (2025 Puerto Bahia Debt)

As part of the acquisition of IVI, the Company consolidated a financial derivative to manage exposure to cash flow risks from the fluctuation of the interest rate expressed in LIBOR on the 2025 Puerto Bahia Debt. Refer to "Liquidity and Capital Resources" section on page 16 for further information. As at March 31, 2021, the Company had the following interest rate swap contract outstanding:

				Avg. Strike Prices	Carrying Amount ($M)	
Type of Instrument	**Term**	**Benchmark**	**Notional Amount $M**	**Floating rate**	**Assets**	**Liabilities**
Swap	April 2021 to June 2025	LIBOR + 180	135,100	3.9%	—	11,673
Total as at March 31, 2021					**—**	**11,673**

Income Tax Expense

($M)	Three months ended March 31 2021	2020
Current income tax expense	(4,191)	(5,095)
Deferred income tax expense	(9,089)	(167,979)
Total income tax expense	**(13,280)**	**(173,074)**

Current income tax expense for the first quarter of 2021 was $4.2 million, compared with $5.1 million in the same quarter of 2020. The reduction is mainly due to the reduction in the minimum tax rate in Colombia from 0.5% to 0% for 2021 partially offset by withholding taxes on dividends from ODL during the first quarter of 2021. Deferred income tax expense for the first quarter of 2021 was $9.1 million compared with $168.0 million primarily due to the derecognition of deferred tax assets in Colombia in the comparable period of 2020 driven by the reduction in global crude oil prices.

Net Loss

($M)	Three months ended March 31 2021	2020
Net loss attributable to equity holders of the Company	(14,126)	(387,809)
Per share – basic ($)	(0.14)	(4.04)
Per share – diluted ($)	(0.14)	(4.04)

The Company reported a net loss of $14.1 million for the first quarter of 2021 which included a loss on risk management contracts of $19.8 million, foreign exchange loss of $18.5 million, and finance expense of $13.6 million partially offset by $51.5 million of operating income. This compared to a net loss of $387.8 million in the first quarter of 2020, which included a loss from operations of $215.1 million (including a non-cash impairment charge of $150.8 million), and deferred income tax expense of $168.0 million.

Capital Expenditures

($M)	Three months ended March 31 2021	2020
Development capital	8,095	47,795
Exploration activities [(1)]	5,682	16,770
Infrastructure and other capital	588	111
Total capital expenditures	**14,365**	**64,676**

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

Capital expenditures for the three months ended March 31, 2021, were $14.4 million which was 78% lower than the same period of 2020. During the first quarter of 2021, the Company completed one development well in CPE-6 as well as the mobilization of four rigs in Colombia. In Guyana, the Company, through its majority-owned subsidiary and joint venture partner CGX, continues its preparation activities to spud Kawa-1 exploration well in the Corentyne block and developed seismic modelling studies work for the Makarapan-1 exploration well in the Demerara block. During the first quarter of 2020, 18 development wells and three exploration wells were drilled.

Compared with the capital investment of $24.9 million in the fourth quarter of 2020, expenditures were lower in the first quarter primarily due to delays in ramping up development activities in an effort to protect the Company's cash position until clarity on improving oil prices emerged. Currently, development activity has returned to normal levels with five rigs in operation and the Company expects this current level of activity and increased capital spending in line with guidance ranges to continue through the end of 2021.

Selected Quarterly Information

Operational and financial results		2021 Q1	2020 Q4	2020 Q3	2020 Q2	2020 Q1	2019 Q4	2019 Q3	2019 Q2
Heavy crude oil production	(bbl/d)	20,997	21,074	21,997	22,533	31,996	32,586	33,906	32,462
Light and medium crude oil production	(bbl/d)	18,685	19,756	19,820	18,415	29,539	36,095	34,024	39,469
Total crude oil production	(bbl/d)	39,682	40,830	41,817	40,948	61,535	68,681	67,930	71,931
Conventional natural gas production	(mcf/d)	5,227	6,356	7,895	9,399	11,611	12,677	13,013	13,988
Total production	(boe/d)	40,599	41,945	43,202	42,597	63,572	70,905	70,213	74,385
Sales volumes, net of purchases (D&P) - (boe)[1]	(boe/d)	34,555	44,551	39,966	35,963	34,186	65,646	54,163	64,698
Brent price	($/bbl)	61.32	45.26	43.34	33.39	50.82	62.42	62.03	68.47
Oil & gas sales, net of purchases [1]	($/boe)	58.18	42.20	40.18	24.96	41.57	58.56	56.65	66.02
Realized (loss) gain on risk management contracts	($/boe)	(3.53)	(2.00)	(1.70)	12.19	2.65	(0.66)	(0.43)	(0.34)
Royalties	($/boe)	(1.96)	(0.47)	(0.23)	—	(1.18)	(0.98)	(2.42)	(2.45)
Diluent costs	($/boe)	(2.13)	(1.75)	(1.52)	(2.53)	(1.28)	(0.55)	(0.38)	(1.81)
Net sales realized price	($/boe)	50.56	37.98	36.73	34.62	41.76	56.37	53.42	61.42
Production costs	($/boe)	(10.54)	(13.46)	(8.97)	(9.03)	(12.48)	(13.76)	(11.60)	(11.17)
Transportation costs	($/boe)	(10.89)	(10.93)	(9.89)	(11.28)	(12.44)	(12.84)	(12.00)	(12.49)
Operating netback	($/boe)	29.13	13.59	17.87	14.31	16.84	29.77	29.82	37.76
Revenue	($M)	184,734	177,109	152,760	81,701	236,938	351,027	277,676	377,347
Net (loss) income	($M)	(14,126)	48,636	(90,473)	(67,760)	(387,809)	69,408	(49,117)	227,809
Per share – basic ($)	($)	(0.14)	0.50	(0.93)	(0.70)	(4.04)	0.71	(0.50)	2.32
Per share – diluted ($)	($)	(0.14)	0.48	(0.93)	(0.70)	(4.04)	0.70	(0.50)	2.29
General and administrative	($M)	13,202	19,851	10,539	9,716	15,015	22,897	18,476	18,207
Operating EBITDA	($M)	69,158	35,639	52,113	37,608	46,982	137,052	124,586	179,665
Capital expenditures	($M)	14,365	24,871	2,905	15,651	64,676	132,452	70,761	73,487

1.Prior period figures are different compared with those previously reported as a result of the change in the treatment of purchased volumes and cost of purchases according with the new operating netback approach. Refer to "Non-IFRS Measures" section on page 14 for further details.

Over the past eight quarters, the Company's sales have fluctuated due to changes in production, timing of cargo shipments, movement in Brent benchmark prices, and fluctuations in crude oil price differentials. In addition to decreases in the Company's production since 2019 due to natural declines on its mature fields, during the past four quarters there was a significant reduction in production resulting from the voluntary shut-in of production from certain blocks during the second and third quarters of 2020 due to the low global crude oil price environment and the impact of the COVID-19 pandemic, significant reduction of capital spending, the cessation of production in Peru since March 2020 and the reduction in transportation cost in 2020 and 2021 due to the cessation of payments for unused facilities under the BIC Ancillary Agreements and CLC Ancillary Agreements. For further information refer to Note 28 of the 2020 Annual Consolidated Financial Statements.

Trends in the Company's net (loss) income are also impacted most significantly by the recognition and derecognition of deferred income taxes, DD&A, impairment charges of oil, gas and other assets, reclassification of currency translation adjustment on the acquisition of IVI, recognition of contingency provision from the Conciliation Agreement (refer to "Conciliation Agreement" section on page 19 for further details), and total (loss) gain from risk management contracts that fluctuate with changes in hedging strategies and crude oil benchmark forward prices.

Refer to the Company's previously issued annual and interim Management Discussion and Analysis available on SEDAR at www.sedar.com for further information regarding changes in prior quarters.

Midstream Activities

The Company has investments in certain infrastructure and midstream assets which includes storage and other facilities relating to the distribution and exportation of crude oil products in Colombia and the Company's investments in pipelines. The midstream segment principally includes the following assets:

Project [1]	Description	Interest	Accounting Method
Puerto Bahia	Bulk liquid storage and import-export terminal	94.16% interest in Puerto Bahía	Consolidation
ODL Pipeline	Crude oil pipeline, capacity of 300,000 bbl/day	59.93% interest in ODL JV (which holds a 35% interest in the ODL Pipeline)	Equity Method [2]
Bicentenario Pipeline ("**BIC Pipeline**")	Crude oil pipeline, capacity of 120,000 bbl/day	43.03% equity interest in Bicentenario	Equity Method [2][3]

1. The Midstream segment also includes the Company's interest in three other pipelines in Colombia: the Oleoducto Guaduas-La Dorada pipeline, Oleoducto del Alto Magdalena pipeline, and Oleoducto de Colombia pipelines.Results of operations from these pipelines are not significant to the Company's consolidated financial results.
2. Equity method accounting 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.
3. As a result of the reclassification of the Bicentenario investment to asset held for sale, the equity method was stopped in the fourth quarter of 2020.

Puerto Bahia

Puerto Bahia owns and operates a multifunctional port facility located in Cartagena, Colombia which consists of a hydrocarbon terminal and a dry cargo terminal adjacent to the Bocachica access channel of the Cartagena Bay, and is strategically located near the Cartagena Refinery. On August 6, 2020, the Company increased its ownership of IVI from 39.22% to 71.57% and as a result, began to consolidate Puerto Bahia. On December 30, 2020, the Company further increased its ownership to 94.16% through the conversion of certain debt into preferred shares with voting rights.

For the three months ended March 31, 2020, prior to the acquisition of a controlling interest in Puerto Bahia on August 6, 2020, the Company had recognized $25.1 million as its share of losses from IVI mainly due to higher unrealized foreign exchange losses on the revaluation of Puerto Bahia's USD-denominated bank debt. For the three months ended March 31, 2021 Puerto Bahia has generated $10.0 million of segment operating income primarily from take-or-pay contracts in its liquid bulk storage terminal business.

ODL Pipeline

The Company holds a 59.93% interest in ODL JV, which has a 35% equity investment in Oleoducto de los Llanos Orientales ("**ODL")**. ODL owns the Oleoducto de los Llanos pipeline, which connects the Rubiales, Quifa and Llanos-34 fields to the Monterrey Station or Cusiana Station in the Casanare Department.

For the three months ended March 31, 2021, the Company recognized $9.8 million as its share of income from ODL which was $2.4 million lower than the same period of 2020 primarily due decrease in the transportation tariff since the second quarter 2020 and impact of foreign exchange fluctuations. During the three months ended March 31, 2021, the Company recognized gross dividends of $41.6 million and a return of capital of $4.2 million. As at March 31, 2021, the Company has accounts receivables of $28.5 million of dividends and return of capital contributions.

Bicentenario Pipeline

The Company holds a 43.03% interest in Bicentenario, which owns the 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 November 16, 2020, the Company, Bicentenario and Cenit Transporte y Logística de Hidrocarburos S.A.S. ("**Cenit**") signed a Conciliation Agreement, which includes a full and final mutual release upon closing of all present and future amounts claimed by all parties in respect of terminated transportation and other contracts for both the CLC Pipeline and the BIC Pipeline. Refer to the "Conciliation Agreement Update" section on page 19 for further details.

As at March 31, 2021, the Company has recorded a discounted carrying value of dividends receivable from Bicentenario of $55.2 million ($56.9 million undiscounted) and as at March 31, 2021, the balance of the investment in Bicentenario is $60.8 million recognized in assets held for sale.

Midstream Segment Results

The Company's Interim Financial Statements include the following amounts relating to the midstream segment:

	Three months ended March 31	
($M)	**2021**	**2020**
Revenue	16,845	—
Costs	(4,528)	—
General and administrative	(1,476)	—
Depletion, depreciation and amortization	(793)	—
Segment income from operations	**10,048**	**—**
Share of Income from associates - ODL	9,786	12,161
Share of Income from associates - Bicentenario	—	4,512
Share of loss from associates - IVI	—	(25,079)
Segment income (loss)	**19,834**	**(8,406)**

Non-IFRS Measures

This MD&A contains the following terms that do not have standardized definitions in IFRS: "operating EBITDA," "Oil & gas sales, net of purchases," "net sales," "operating netback," "consolidated total indebtedness," and "net debt." 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 also reports "consolidated net tangible assets" and "consolidated adjusted EBITDA" in accordance with the terms of the Indenture (as defined on page 18). Refer to the "Liquidity and Capital Resources – Covenants" section on page 16.

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 (loss) income 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 following items: restructuring, severance and other costs, certain non-cash items (such as impairments, foreign exchange, unrealized risk management contracts, costs under terminated pipeline contracts and share-based compensation) and gains or losses arising from the disposal of capital assets. In addition, other unusual or non-recurring items are excluded from operating EBITDA, as they are not indicative of the underlying core operating performance of the Company.

The following table provides a reconciliation of net loss to operating EBITDA:

	Three months ended March 31	
($M)	**2021**	**2020**
Net loss	(14,126)	(387,809)
Finance income	(840)	(4,678)
Finance expenses	13,587	15,260
Income tax expense	13,280	173,074
Depletion, depreciation and amortization	32,636	88,020
Impairment and others	(5,738)	148,134
Costs under terminated pipeline contracts	—	2,839
Share-based compensation	1,317	1,217
Restructuring, severance and other costs	381	6,408
Share of (income) loss from associates	(9,786)	8,406
Foreign exchange loss	18,488	20,597
Unrealized loss (gain) on risk management contracts	8,838	(29,140)
Other loss, net	9,601	2,991
Non-controlling interests	1,520	1,663
Operating EBITDA	**69,158**	**46,982**

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, including the cost of any volumes purchased from third parties. 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 and cost of purchases is helpful to understand the Company's sales performance based on the net realized proceeds from its own production net of diluent, the cost of which is partially recovered when the blended product is sold. Net sales also excludes sales from port services, as it is not considered part of the oil & gas segment. Refer to the reconciliation in the "Sales" section on page 6.

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 any trading activities and results from its Midstream segment from the per barrel metrics. Refer to the reconciliation in the "Operating Netback" section on page 6.

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

Oil & gas sales, net of purchases, on a per boe basis is calculated using oil and gas sales less the cost of volumes purchased from third parties including its transportation and refining cost, divided by the total sales volumes from D&P assets, net of purchases. A reconciliation of this calculation is provided below:

	Three months ended March 31	
	2021	**2020**
Oil and gas sales ($M) [1]	184,960	243,838
(-) Cost of purchases ($M) [2]	(4,004)	(1,003)
Oil & gas sales, net of purchases ($M)	**180,956**	**242,835**
Sales volumes, net of purchases (D&P) - (boe)	3,109,950	5,840,926
Oil & gas sales, net of purchases ($/boe)	58.18	41.57

1. Excludes sales from port services as they are not part of the oil & gas segment. For further information, refer to the "Midstream Activities" section on page 13.
2. Cost of third-party volumes purchased for use and resale in the Company's oil operations, including its transportation and refining costs.

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

	Three months ended March 31	
	2021	**2020**
Net sales ($M)	157,252	243,957
Sales volumes, net of purchases (D&P) - (boe)	3,109,950	5,840,926
Net sales realized price ($/boe)	50.56	41.76

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 March 31	
	2021	**2020**
Production costs ($M)	38,513	72,210
Production (boe)	3,653,910	5,785,052
Production costs ($/boe)	10.54	12.48

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 March 31	
	2021	**2020**
Transportation costs ($M)	37,084	66,052
Net production (boe)	3,405,330	5,308,121
Transportation costs ($/boe)	10.89	12.44

Consolidated Total Indebtedness and Net Debt

Consolidated total indebtedness and net debt are used by the Company to monitor its capital structure, financial leverage, and as a measure of overall financial strength. Consolidated total indebtedness is defined as long-term debt, plus liabilities for leases and net position of risk management contracts, excluding the Unrestricted Subsidiaries. This metric is consistent with the definition under the Indenture for the calculation of certain conditions and covenants. Net debt is defined as consolidated total indebtedness less cash and cash equivalents. Both measures are exclusive of non-recourse subsidiary debt (2025 Puerto Bahia Debt) and certain amounts attributable to the Unrestricted Subsidiaries.

The following table reconciles both measures to amounts reported under IFRS:

	As at March 31
($M)	**2021**
Long-term debt	336,915
Total lease liabilities (1)	14,351
Risk management liabilities, net(2)	10,433
Consolidated Total Indebtedness excluding 2025 Puerto Bahia Debt	361,699
(-) Cash and Cash Equivalents (3)	(222,372)
(=) Net Debt excluding 2025 Puerto Bahia Debt	139,327

1. Excludes $0.3 million of lease liabilities attributable to the Unrestricted Subsidiaries.
2. Excludes $11.0 million of risk management liabilities attributable to the Unrestricted Subsidiaries.
3. Excludes $25.9 million of cash and cash equivalents attributable to the Unrestricted Subsidiaries.

4. LIQUIDITY AND CAPITAL RESOURCES

The Company's principal liquidity and capital resource requirements include:

- 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 shareholders returns through 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. The Company regularly reviews its capital structure and liquidity sources with a focus on ensuring that capital resources will be sufficient to meet operational needs and other obligations.

As at March 31, 2021, the Company had a total cash balance of $409.5 million (including $161.2 million in restricted cash), which is $8.2 million higher than at December 31, 2020. For the three months ended March 31, 2021, the Company generated $47.4 million in operating cash flows which was used to fund cash outflows of $21.3 million for capital expenditures and other investing activities. Financing outflows of $6.0 million for the three months ended March 31, 2021 included $4.2 million in lease payments, $0.5 million of interest and other financing charges, and $1.3 million to repurchase common shares under its NCIB.

Since the third quarter of 2020, the Company's consolidated working capital position was reduced to a deficit due to the acquisition of IVI, which resulted in the consolidation of the 2025 Puerto Bahia Debt ($183.1 million as of March 31, 2021) and classification as a current liability (for further information of the 2025 Puerto Bahia Debt refer to "Puerto Bahia Secured Syndicated Credit Loan" section on page 17 and Note 20 of the 2020 Annual Consolidated Financial Statements). As of March 31, 2021, working capital deficit reduced to $39.8 million compared with $111.7 million at year-end as a result of the improvement in the realized price of volumes sold during the quarter. The Company believes that working capital balances in conjunction with future cash flows from operations and available credit facilities are sufficient to support the Company's normal operating requirements, capital expenditures and financial commitments on an ongoing basis.

Restricted cash includes amounts that have been set aside and are not available for immediate disbursement. As of March 31, 2021, the main components of restricted cash were long-term abandonment funds as required by the ANH, cash collateral required for certain legal proceedings, and restricted funds related to the 2025 Puerto Bahia Debt. 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 third 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 is expected to be released as the related processes are closed. As of March 31, 2021, total restricted cash of $161.2 million, decreased by $7.7 million from December 31, 2020, primarily due the impact from foreign exchange. Subsequent to the end of the first quarter, the Company released $12.5 million of restricted cash relating to exploration commitments due to the reduction in cash collateral requirements under new letter of credit lines.

The measures taken by the Company to manage its liquidity and capital resources are ongoing and the Company continues to look for additional opportunities to manage its costs and commitments. Based on the foregoing, including the expected impacts of such measures, the Company expects that unrestricted cash balances in conjunction with future cash flows from operations, available credit facilities, and alternate financing arrangements, will be sufficient to support its working capital deficit, operational and capital requirements and other financial commitments. The Company will remain flexible and disciplined with respect to capital allocation decisions as the current commodity price environment evolves and can make additional changes to its business and operations as warranted. See also the "Risks and Uncertainties" section on page 21.

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.

Puerto Bahia Secured Syndicated Credit Loan

During the third quarter of 2020, the Company acquired control of IVI which holds 99.9% of Puerto Bahia (for further information refer to Note 20 of the 2020 Annual Consolidated Financial Statements).

In October 2013 Puerto Bahia entered into a credit agreement with a syndicate of lenders for a $370 million debt facility, which matures in June 2025, for the construction and development of the port (the "**2025 Puerto Bahia Debt**"). During the course of 2018, 2019 and 2020 the lenders gave notices stating that Puerto Bahia is in breach of various loan covenants but did not accelerate the loan. As a result, the total amount outstanding under the 2025 Puerto Bahia Debt is presented as a current liability in accordance with IAS 1. The 2025 Puerto Bahia Debt bears interest at 6-month LIBOR plus 5% which is payable semi-annually, which is secured by substantially all the assets and shares of Puerto Bahia, and which is non recourse to the Company (other than as provided for by the equity contribution agreement ("**ECA**") described below), and it has no impact on the Company's financial covenants under the Unsecured Notes. As at March 31, 2021, the 2025 Puerto Bahia Debt outstanding amount is $183.1 million.

As part of the agreements for the bank loan to fund the construction of Puerto Bahia, the Company entered into the ECA signed on October 4, 2013. Under the ECA, the Company and IVI agreed jointly and severally to cause contributions (via debt or equity) to Puerto Bahia up to the aggregate amount of $130.0 million whenever Puerto Bahia had a deficiency in the reserve account supporting its bank loan. Amounts disbursed under the ECA are designated to the repayment of principal and interest from that loan. Pursuant to the terms of the ECA, Frontera has from time to time made loans to Puerto Bahia ("**ECA Loans**") that are subordinated to the 2025 Puerto Bahia Debt and bear interest of 14%. The ECA Loans give Frontera a direct claim against Puerto Bahia that is in priority to IVI's equity interest in Puerto Bahia, and thus indirectly in priority to the claims of the remaining minority shareholders of IVI.

To date, the Company has advanced a total of $73.9 million under the ECA Loans, of which $41.3 million was capitalized into preferred shares of Puerto Bahia during the fourth quarter of 2020 (refer to the "Midstream Activities" section on page 13 for further details). As a result of the acquisition of IVI, all intercompany balances and transactions between the Company and IVI are eliminated on consolidation.

Letters of Credit

The Company has various uncommitted bilateral letter of credit lines. As of March 31, 2021, the Company had issued letters of credit and guarantees for exploration, operational, and transport commitments totaling $81.5 million, with cash collateral of $33.5 million. During the first quarter of 2021, the Company increased credit lines with Bancolombia and Banco BTG Pactual S.A. to $39.0 million. These new uncommitted credit lines do not require cash collaterals and Frontera expects that these increased limits will enable the Company to release additional restricted cash amounts in the second quarter of 2021.

Unsecured Notes 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 the Unsecured Notes, the Company (excluding the Unrestricted Subsidiaries) may, among other things, incur indebtedness provided that the consolidated debt to consolidated adjusted EBITDA ratio(1) is less than or equal to 3.0:1.0 and the consolidated fixed charge ratio(2) is greater than or equal to 2.5:1.0. In the event that 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(3). 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 March 31, 2021, the Company is in compliance with all such covenants.

As of March 31, 2021, and pursuant to requirements under the Indenture, the Company reports consolidated net tangible assets of $1,036,021,000 consolidated total indebtedness of $361,699,000 consolidated adjusted EBITDA of $205,749,000 and consolidated interest expense of $34,571,000.

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.

   a. Consolidated total indebtedness is defined under "Non-IFRS Measures" on page 14.

   b. 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; after excluding the impact of the Unrestricted Subsidiaries.

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.
3. Consolidated net tangible assets is defined in the Indenture as the net amount of the Company's total assets less intangible assets and current liabilities, after excluding the impact of the Unrestricted Subsidiaries.

Commitments and Contractual Obligations

The Company's commitments and contractual obligations as at March 31, 2021, undiscounted by calendar year, are presented below:

As at March 31, 2021 ($M)	2021	2022	2023	2024	2025	Total
Financial obligations						
Long-term debt, including interest payments	33,958	33,958	366,802	—	—	434,718
Lease liabilities	7,587	5,517	3,007	68	56	16,235
2025 Puerto Bahía Debt and interest (1)	48,897	47,259	50,075	47,699	13,601	207,531
Total financial obligations	**90,442**	**86,734**	**419,884**	**47,767**	**13,657**	**658,484**
Transportation and storage commitments						
Ocensa P-135 ship-or-pay agreement	$ 52,120	$ 69,493	$ 69,493	$ 69,493	$ 34,954	$ 295,553
ODL agreements (2)	5,153	—	—	—	—	5,153
Other transportation agreements	5,825	—	—	—	—	5,825
Exploration commitments						
Minimum work commitments (3)	73,382	120,094	37,127	3,600	—	234,203
Other commitments						
Operating purchases, leases and community obligations	17,408	9,388	8,952	13,368	2,145	51,261
Total Commitments	**153,888**	**198,975**	**115,572**	**86,461**	**37,099**	**591,995**

1. For financial reporting purposes, the 2025 Puerto Bahia Debt is classified as a current liability. Amounts shown in the table are in accordance with the repayment schedule.
2. Includes amounts for the new ODL transportation contract until June 30, 2021. If the Conciliation Agreement closes, additional commitments will extend until 2024. Refer to "Conciliation Agreement" for further details in Note 28 of 2020 Annual Consolidated Financial Statements.
3. Includes minimum work commitments relating to exploration activities in Colombia and Ecuador until the contractual phase when the Company should decide whether to continue or relinquish the exploration areas. The Company, through its interests in CGX, has other exploration work commitments in Guyana as described on page 19.

Guyana Exploration

As of March 31, 2021, the Company, through its 73.85% interest in CGX, has exploration work commitments under its Petroleum Prospecting Licenses ("**PPL**") for blocks in Guyana, as follows:

- In accordance with the Corentyne PPL, which is currently in phase one of the second renewal period, one (1) exploration well must be drilled by November 27, 2021.
- In accordance with the Demerara PPL, which is currently in phase one of the second renewal period, one (1) exploration well must be drilled by February 11, 2022.
- In accordance with the Berbice PPL, which is currently in phase one of the second renewal period, the Company shall complete a seismic program, including all associated processing and interpretations, by August 12, 2021.

The Company, through its interest in CGX, has entered into an agreement with a third party to complete drilling activities in 2021 on the Corentyne block. Under the agreement, the Company has provided a parent guarantee in the event of non-performance by CGX for certain obligations up to a maximum of $25.0 million.

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.

Conciliation Agreement

On November 16, 2020, the Company, Cenit and Bicentenario reached an agreement (the "**Conciliation Agreement**") for the joint filing of a petition for binding settlement which, upon completion and approval by Administrative Tribunal of Cundinamarca (the "**Court**"), will resolve all the disputes between the parties related to the BIC Pipeline and the CLC Pipeline, and will terminate all the pending arbitration proceedings related to such disputes, including the Bicentenario Arbitration, CLC Arbitration and International Arbitration. For further information refer to Note 28 of the 2020 Annual Consolidated Financial Statements.

On March 24, 2021, the Company announced that the Office of the Procuraduría General de la Nación has delivered its opinion on the Conciliation Agreement. The opinion is favorable, recommending that the conciliation be approved. The terms of the Conciliation Agreement remain the same as previously disclosed.

Delivery of the favorable opinion by the Procuraduría General de la Nación represents the first of two stages of review of the Conciliation Agreement. If the Conciliation Agreement is approved by Court, the second stage of the process will be completed, and the parties will be able to complete the settlement arrangement. There can be no assurance that Court approval will be received on a timely basis or at all.

Given the favorable opinion delivered by the Procuraduría General de la Nación, recommending that the Conciliation Agreement be approved, the Company, Cenit and Bicentenario have agreed to extend the deadline for the approval of the Conciliation Agreement from June 30, 2021 to September 30, 2021 or such later date as may be further agreed. If the Conciliation Agreement is not approved by September 30, 2021, then either party will become entitled to terminate the settlement arrangement, and the legal rights of the parties with respect to the disputes will not be prejudiced unless and until the required approval is obtained and the settlement arrangement is closed.

5. OUTSTANDING SHARE DATA

The Company has the following outstanding share data as at May 3, 2021:

	Number
Common shares	96,962,295
Deferred share units ("**DSUs**") (1)	739,179
Restricted share units ("**RSUs**") (2)	2,349,700

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/or the achievement of corporate objectives. The value of an 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

During the first quarter of 2020, the Company suspended its quarterly dividend due to the oil price decline. Prior to the suspension, the Company had paid dividends during 2020 as presented in the table below. The declaration and payment of any specific dividend, including the actual amount, declaration date and record date are subject to the discretion of the Board of Directors. In response to the volatility in oil prices, the Company has not reinstated its quarterly dividend but intends to utilize share repurchases under its NCIB as described below.

Declaration Date	Record Date	Payment Date	Dividend (C$/Share)	Dividends Amount ($M)	Number of DRIP Shares (1)
November 7, 2019	January 3, 2020	January 17, 2020	0.205	15,125	474,568
March 5, 2020	April 2, 2020	April 16, 2020	0.205	13,966	1,679,065
Total			0.410	29,091	2,153,633

1. The Company has a dividend 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.

Normal Course Issuer Bid

On March 15, 2021, the TSX approved the Company´s notice to initiate a NCIB, for its common shares. Pursuant to the NCIB, the Company may purchase for cancellation up to 5,197,612 of its Common Shares during the twelve-month period commencing March 17, 2021 and ending March 16, 2022 representing approximately 10% of the Company's "public float" (as calculated in accordance with TSX rules). Purchases subject to the NCIB will be carried out pursuant to open market transactions through the facilities of the TSX or alternative trading systems, if eligible, by BMO Nesbitt Burns Inc. ("**BMO**"), on behalf of Frontera in accordance with the plan and applicable regulatory requirements. During the first quarter of 2021, the Company purchased 262,000 Common Shares under the new NCIB. As at May 3, 2021, the Company had repurchased for cancellation a total of 768,800 Common Shares for $4.0 million with an additional 4,428,812 Common Shares available for repurchase under the NCIB.

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

	Three months ended March 31 2021
Number of common shares repurchased	262,000
Total amount of common shares repurchased ($M)	1,316
Weighted-average price per share ($)	5.02

6. RELATED-PARTY TRANSACTIONS

The following tables provide the transaction amounts, total balances outstanding and commitments with related parties, as at March 31, 2021 and December 31, 2020, and for the three months ended March 31, 2021 and 2020, respectively:

($M)		Accounts Receivable (1)	Accounts Payable	Commitments (2)	Cash Advance (1)
ODL	2021	28,546	5,400	5,153	—
	2020	465	7,821	7,888	—
Bicentenario	2021	68,293	—	—	87,278
	2020	70,761	—	—	87,278

($M)		Three months ended March 31 Purchases / Services	Three months ended March 31 Interest Income (1)
ODL	2021	9,072	—
	2020	11,963	—
Bicentenario	2021	—	—
	2020	1,229	—
IVI (3)	2021	—	—
	2020	9,818	4,511

1. Amounts presented based on contractual payment obligations undiscounted and prior to impairments.
2. Refer to the "Commitments and Contractual Obligations" section on page 18.
3. 2020 balances shown reflect transactions before the Company acquired control of IVI on August 6, 2020.

7. RISKS AND UNCERTAINTIES

The Company is exposed to a variety of known and unknown risks in the pursuit of its strategic objectives including, but not limited to: production; liquidity/financial; health, safety and environmental; exploration, new business and reserves growth; information security; and political risk. 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 seeks to systematically mitigate these risks to an acceptable level. In addition, we continuously monitor our risk profile as well as industry best practices.

For a comprehensive discussion of the risks and uncertainties that could have an effect on the business and operations of the Company, investors are urged to review the AIF and 2020 Annual Consolidated Financial Statements as of December 31, 2020, copies of which are available on SEDAR at www.sedar.com.

In addition, the ongoing COVID-19 pandemic has had and could continue to have a negative impact on the Company's financial condition, results of operations, and cash flows. The risk of a resurgence or additional variant strains remains high and delays in vaccine rollouts could result in continued fluctuations in the price of oil and natural gas products. The extent to which such events impact the Company's business, financial condition and results of operations will depend on future developments, which are highly uncertain and cannot be predicted with any degree of confidence. Such events have had, and could continue to have, a material adverse effect on the Company's business, financial condition and results of operations. Even after the COVID-19 pandemic has subsided, the Company may continue to experience materially adverse impacts to its business as a result of the pandemic's global economic impact. To the extent that the COVID-19 pandemic adversely affects the Company's business, financial condition and results of operations, it may also have the effect of heightening many of the other risks described herein and in the Company's AIF.

See the "Liquidity and Capital Resources" section on page 16 for additional detail on the steps the Company has taken to mitigate or manage some of these risks. However, the situation continues to be dynamic and highly uncertain, and the effectiveness and adequacy of such measures cannot be determined at this time.

8. ACCOUNTING POLICIES, CRITICAL JUDGMENTS AND ESTIMATES

The Interim 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 2020 Annual Consolidated Financial Statements. The Company has not early adopted any standard, interpretation or amendment that has been issued but is not yet effective. Recent accounting pronouncements of significance or potential significance are described in Note 3b of the 2020 Annual Consolidated Financial Statements, including management's evaluation of impact and implementation progress.

The preparation of the Interim 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 Interim 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.

The effect of the COVID-19 pandemic on the world economy, and the associated volatility in oil prices, has impacted and continues to impact the Company and has significantly increased economic uncertainty. The Company continues to monitor this rapidly changing environment and the impact on the Company's business, financial conditions and results of operations, however the duration and magnitude of these events remains unknown at this time. There may also be effects that are not currently known, as the full impact and duration of the COVID-19 pandemic is still uncertain. As a result, it is difficult to reliably assess the full impact this will have on the Company's business, financial conditions and results of operations which presents uncertainties and risks in management's judgments, estimates, and assumptions used in the preparation of the Interim Financial Statements.

The results of the economic downturn and any potential resulting direct and indirect impact to the Company has been considered in management's judgments and estimates as described above for the quarter end; however there could be further prospective material impacts in future periods. As such, actual results may differ from these estimates under different assumptions or conditions. A summary of the significant judgments and estimates made by management in the preparation of its financial information is provided in Note 3c of 2020 Annual Consolidated Financial Statements.

9. 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 Interim 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.

There have been no changes in the Company's ICFR during the quarter ended March 31, 2021, 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 interim filings are being prepared, and that 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.

10. 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 which expired in February 5, 2021. Under this contract, the volumes produced were owned by Perupetro and the Company was entitled to in-kind payments on production, which ranged from 44% to 84% of production on the block. The Company reported 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		
Producing blocks in Colombia		**Q1 2021**	**Q4 2020**	**Q1 2020**
Heavy oil	(bbl/d)	19,632	19,694	29,350
Light and medium oil	(bbl/d)	17,288	18,318	22,449
Conventional natural gas production	(mcf/d)	5,227	6,356	11,611
Net production Colombia	**(boe/d)**	**37,837**	**39,127**	**53,836**
Producing blocks in Peru				
Light and medium oil	(bbl/d)	—	—	4,495
Net production Peru (1)	**(bbl/d)**	**—**	**—**	**4,495**
Total net production	**(boe/d)**	**37,837**	**39,127**	**58,331**

1. No production in Peru after the first quarter 2020, due to on February 27, 2020, Block 192 was placed in force majeure as a result of a community blockade. Then, on February 5, 2021 the service contract for Block 192 expired.

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 7.

Boe Conversion

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

Abbreviations

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

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